UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________________ to ___________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES x NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

x

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

YES x NO o

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2004 $1,009,062,621

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 28, 2005
Common stock, $1.00 par value	32,526,662 shares

Documents Incorporated by Reference

1. Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2005 Annual Meeting of Stockholders to be held on May 25, 2005, are incorporated by reference in Part I, Item 4A and Part III of this Form 10-K.

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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

Black Hills Corporation, a South Dakota corporation, is a diversified energy company and a public utility holding company under the Public Utility Holding Company Act of 1935, as amended (PUHCA). Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941 and began selling and marketing various forms of energy on an unregulated basis in 1956. We operate principally in the United States with two major business groups: wholesale energy and retail services.

Wholesale Energy Group

Our wholesale energy group, which operates through Black Hills Energy, Inc. (Black Hills Energy) and its subsidiaries, conducts business in four segments:

Power Generation. We engage in the production and sale of electric capacity and energy through a diversified portfolio of generating plants predominantly in the Rocky Mountain and Western regions of the United States.

Oil and Gas. We produce natural gas and crude oil primarily in the Rocky Mountain region of the United States.

Coal Mining. In our coal mining segment, we engage in the mining and production of coal at our Wyodak coal mine located near Gillette, Wyoming.

Energy Marketing and Transportation. We market and transport fuel products primarily in the Western and Mid-continent regions of the United States and in Western Canada.

Retail Services Group

Our retail services group currently consists of our electric utility and communications segments. In future filings, we will report the operations of our new combination electric and gas public utility, Cheyenne Light, Fuel and Power Company (CLF&P), as its own segment.

Electric Utility. Through Black Hills Power, Inc. (Black Hills Power), our existing electric utility segment engages in the generation, transmission and distribution of electricity to approximately 62,000 customers in South Dakota, Wyoming and Montana, and the sale of electric energy and capacity on a wholesale, or “off-system,” basis.

Communications. Our communications segment, operating primarily through Black Hills FiberCom, LLC (Black Hills FiberCom), offers broadband telecommunications services, including local and long distance telephone services, expanded cable television service, cable modem Internet access and high speed data and video services, to approximately 27,000 residential and business customers located in Rapid City and the northern Black Hills region of South Dakota. This segment also has a telephone directory business that serves the greater Rapid City area, the northern and southern Black Hills, and the greater Billings, Montana area.

Combination Electric and Gas Utility. On January 21, 2005, we acquired CLF&P, a combination public utility serving approximately 38,000 electric and 31,000 natural gas customers in Cheyenne, Wyoming and vicinity, which in future filings we will report as a separate segment. Power is supplied to CLF&P under an all-requirements contract with Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, which expires at the end of 2007.

Website Access to Reports

Through our Internet website, www.blackhillscorp.com, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

Safe Harbor for Forward-Looking Information

This Annual Report on Form 10-K includes “forward-looking statements” as defined by the Securities and Exchange Commission (SEC). We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including the Risk Factors set forth in this Form 10-K and the following:

- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- The volumes of our production from oil and gas development properties, which may be dependent upon issuance by federal, state, and tribal governments, or agencies thereof, of drilling, environmental and other permits, and the availability of specialized contractors, work force, and equipment;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- Our ability to successfully integrate CLF&P into our operations;
- Our compliance with orders of the SEC under PUHCA related to our financing and investment authority, and related to transactions and cost allocation among our affiliated companies;
- Our ability to remedy any deficiencies that may be identified in the review of our internal controls;
- The timing and extent of changes in energy-related and commodity prices, interest rates, energy and commodity supply or volume, the cost of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;
- General economic and political conditions, including tax rates or policies and inflation rates;
- Our use of derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- The creditworthiness of counterparties to trading and other transactions, and defaults on amounts due from counterparties;
- The amount of collateral required to be posted from time to time in our transactions;
- Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;
- Changes in state laws or regulations that could cause us to curtail our independent power production;
- Weather and other natural phenomena;
- Industry and market changes, including the impact of consolidations and changes in competition;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The cost and effects on our business, including insurance, resulting from terrorist actions or responses to such actions;
- Capital market conditions, which may affect our ability to raise capital on favorable terms;
- Price risk due to marketable securities held as investments in benefit plans;
- Obtaining adequate cost recovery for our retail operations through regulatory proceedings; and
- Other factors discussed from time to time in our other filings with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly our forward-looking statements, whether as a result of new information, future events or otherwise.

Summary Data

As the following table illustrates, we have experienced significant change over the last five years, primarily as a result of the expansion of our wholesale energy business, volatility in wholesale electric sales and the related margins at our electric utility, Black Hills Power, and completion of the initial buildout and continual improvement in the results of our communication segment. Unusual conditions in the Western energy markets during the first half of 2001 and the latter part of 2000 accounted for approximately $1.40 per share and $0.40 per share of our earnings in 2001 and 2000, respectively.

	2004	2003	2002	2001	2000
Net income available for common (in thousands):					
Wholesale energy	$ 45,447	$ 40,648	$ 39,072	$ 54,701	$ 29,047
Retail services	15,268	18,209	22,957	32,938	25,796
Corporate expenses and intersegment eliminations	(3,466)	(7,571)	(2,995)	(3,284)	(2,363)
Discontinued operations	724	9,936	2,418	3,722	368
Preferred dividends	(321)	(258)	(223)	(527)	(78)
	$ 57,652	$ 60,964	$ 61,229	$ 87,550	$ 52,770
Earnings per share – diluted(1)	$ 1.76	$ 1.97	$ 2.26	$ 3.42	$ 2.37
Total assets (in thousands)	$ 2,056,163	$ 2,063,252	$ 1,999,974	$ 1,651,765	$ 1,252,936
Capital expenditures (in thousands)	$ 90,974	$ 116,691	$ 303,191	$ 594,142	$ 173,517(2)
Generating capacity (megawatts)					
Utility (owned generation)	435	435	435	395	393
Utility (purchased capacity)	50	55	60	65	70
Independent power generation(3)	1,004	1,002	950(4)	617	250
Total generating capacity	1,489	1,492	1,445	1,077	713
Utility electric sales (megawatt-hours):					
Firm electric sales	1,959,969	1,994,819	1,966,060	2,012,354	1,973,066
Wholesale off-system	1,090,827	930,706	979,677	965,030	684,378
Total utility electric sales	3,050,796	2,925,525	2,945,737	2,977,384	2,657,444
Oil and gas reserves (MMcfe)	173,417	156,399	57,793	48,401	44,882
Oil and gas production sold (MMcfe)	12,595	10,843	7,398	7,293	5,278
Coal reserves (millions of tons)	294	263	273	277	275
Tons of coal sold (thousands of tons)	4,780	4,812	4,052	3,518	3,050
Average daily marketing volumes:					
Natural gas physical sales (MMbtus)	1,226,600	897,850	683,500	543,000	567,900
Natural gas financial sales (MMbtus)	514,500	344,050	404,700	504,700	292,900
Crude oil (barrels)	44,900	58,700	57,200	36,500	44,300
Communications:					
Residential customers	23,663	23,878	21,700	15,660	8,368
Revenue Generating Units(5)	56,835	53,568	48,285	32,484	16,634
Business customers	3,317	3,012(6)	3,061	2,250	646
Hybrid fiber coaxial cable miles	845	840	818	737	588

(1) In May 2003 and May 2001, we issued 4.6 million and 3.4 million common stock shares, respectively, which dilutes our earnings per share in subsequent periods.
(2) Excludes the non-cash acquisition of Indeck Capital, Inc.
(3) Includes 40 MWs in 2004 and 2003, respectively, 82 MWs in 2002, 68 MWs in 2001 and 58 MWs in 2000, which are reported as "Discontinued operations."
(4) Includes the 224 megawatt expansion at the Las Vegas cogeneration power plant that was placed in service on January 3, 2003.
(5) Total Revenue Generating Units (RGU) equal the total number of services to which residential customers subscribe. Telephone, cable TV and Internet access each represent an RGU.
(6) In 2003, reported business customers were adjusted for consolidation of multiple-location business customers, business orders and temporary business access lines.

For additional information on our business segments see – ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 23 of NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

Wholesale Energy Group

Our wholesale energy group, which operates through Black Hills Energy and its subsidiaries, engages in the production and sale of electric capacity and energy through ownership of a diversified portfolio of generating plants, the production of coal, natural gas and crude oil primarily in the Rocky Mountain region, and the marketing and transportation of energy products. The wholesale energy group consists of four segments:

- power generation;
- natural gas and crude oil production;
- coal mining; and
- energy marketing and transportation.

Power Generation Segment

Our power generation segment acquires, develops, expands and operates unregulated power plants. We currently hold varying interests in independent power plants in Colorado, Nevada, Wyoming and California with a total net ownership of 935 megawatts, and minority interests in several power-related funds with a net ownership interest of 29 megawatts. We also own a 40 megawatt plant in Massachusetts currently held for sale.

How We Manage Our Portfolio. We maintain a geographically diverse portfolio of power plants in our wholesale business group, with a focus on the western region of the United States. The fuel mix of our unregulated portfolio is approximately 90 percent natural gas-fired and 10 percent coal-fired. We sell capacity and energy under a combination of mid- to long-term contracts, and make certain “spot” sales into the energy markets, thereby allowing us to mitigate the impact of a potential downturn in prices in the future. Currently, we sell approximately 98 percent of our unregulated generating capacity under contracts having terms of greater than one year, and we sell the balance under short-term contracts or by spot sales into the wholesale power markets. We also mitigate our financial exposure in the power generation segment by selling a substantial majority of our unregulated capacity and energy under “tolling” agreements, or agreements under which the power purchaser is responsible for supplying fuel for the facility, thus assuming fuel price risk.

Rocky Mountain and West Coast Facilities. We have approximately 935 megawatts of generating capacity in the Western Electricity Coordinating Council (WECC) states of Colorado, Nevada, Wyoming and California, as follows:

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Fountain Valley	Gas	CO	240.0	100%	240.0	2001
Arapahoe Unit 5 and 6	Gas	CO	80.0	100%	80.0	2000
Arapahoe CC5 Expansion	Gas	CO	50.0	100%	50.0	2002
Valmont Unit 7	Gas	CO	40.0	100%	40.0	2000
Valmont Unit 8	Gas	CO	40.0	100%	40.0	2001
Las Vegas I	Gas	NV	53.0	50%	26.5	1994
Las Vegas II	Gas	NV	224.0	100%	224.0	2002
Gillette CT	Gas	WY	40.0	100%	40.0	2001
Wygen	Coal	WY	90.0	100%	90.0	2003
Ontario	Gas	CA	12.0	50%	6.0	1984
Harbor	Gas	CA	80.0	100%	80.0	1989
Harbor Expansion	Gas	CA	18.0	100%	18.0	2001
Total WECC			967.0		934.5	

Fountain Valley, Arapahoe and Valmont Facilities. Our Fountain Valley, Arapahoe and Valmont plants are wholly owned gas-fired peaking facilities in the Front Range of Colorado, with a total capacity of 450 megawatts. The Fountain Valley and Valmont facilities operate in simple cycle, and the Arapahoe facility operates in combined cycle. We sell all of the output from these plants to PSCo under tolling contracts expiring in 2012.

Las Vegas Cogeneration Facilities. Our Las Vegas I facility is a 53 megawatt, combined-cycle, gas-fired plant northeast of Las Vegas, Nevada, and is a Qualifying Facility, or QF, under the Public Utility Regulatory Policies Act of 1978 (PURPA). We sell 45 megawatts of power from this plant to Nevada Power under a long-term contract that expires in 2024. Under the terms of the Nevada Power contract, we assume the fuel price risk associated with the energy generation. While we own 50 percent of this plant, under accounting principles generally accepted in the United States, we consolidate 100 percent of the plant in our financial statements. Our Las Vegas II facility is a wholly owned, 224 megawatt, combined-cycle, gas-fired plant that became operational early in 2003. In December 2003, we executed a new long-term tolling agreement with Nevada Power for the capacity and power from this plant, which expires December 31, 2013. We obtained regulatory approval for the new contract in March 2004 and commenced selling to Nevada Power under the contract on April 1, 2004.

Gillette CT. The Gillette CT, is a wholly owned simple-cycle, gas-fired combustion turbine located near Gillette, Wyoming at the same site as our Wygen plant and Wyodak mine, has a total capacity of 40 megawatts and became operational in May 2001. We have a 10-year power purchase agreement with CLF&P for the sale of the energy and capacity from this facility. In connection with CLF&P's execution of the all-requirements power purchase agreement with PSCo, the Gillette CT power purchase agreement was temporarily assigned from CLF&P to PSCo for the four-year term of the all-requirements agreement, which expires December 31, 2007. During the remaining term of the temporary assignment, we assume intra-month fuel price risks under this agreement since the fuel price is fixed at the outset of each month and PSCo has the right to dispatch the facility on a day-ahead basis. We are permitted to remarket the energy that is not prescheduled by PSCo.

Wygen Plant. The Wygen plant is a mine-mouth, coal-fired plant with a total capacity of 90 megawatts, which commenced operations in the first quarter of 2003. We have contracts to sell 60 megawatts of unit contingent capacity and energy from this plant to CLF&P with a term of 10 years, and 20 megawatts of unit contingent capacity and energy to the Municipal Energy Agency of Nebraska (MEAN) for a term of 10 years. As with the Gillette CT power purchase agreement, CLF&P has temporarily assigned the Wygen power purchase agreement to PSCo for the term of its all-requirements power purchase agreement, which expires December 31, 2007. We are the lessee of the Wygen plant under a synthetic lease with a financial counterparty, but under accounting principles generally accepted in the United States, we consolidate 100 percent of the plant in our financial statements.

Ontario Cogeneration Facility. Our Ontario facility, a QF, is a 12 megawatt, "Chang-cycle," gas-fired power plant in Ontario, California, which we currently operate as a baseload plant. Electrical output from the plant is subject to a 25-year power purchase agreement with Southern California Edison (SCE), which expires in January 2010. The project also sells steam production to Sunkist Growers, Inc. under a five-year agreement, which terminates in November 2007. We own 50 percent of this plant, and under accounting principles generally accepted in the United States, we consolidate 100 percent of the plant in our financial statements.

Harbor Cogeneration Facility. Harbor Cogeneration is a 98 megawatt, combined-cycle, gas-fired plant located at the Port of Long Beach, California. Through October 2004, the facility sold capacity and energy under a summer tolling agreement with SCE. We entered into a new tolling agreement with SCE under which SCE will purchase all of the capacity and energy of the facility commencing April 1, 2005 through May 31, 2008. Under a termination agreement with SCE pertaining to a long-term contract that was previously terminated, Harbor Cogeneration also receives payments pursuant to a termination payment schedule for a period ending on October 1, 2008.

Northeast Facilities. During 2003, we decided to exit the Eastern market and divest our assets in that region. In September 2003, we completed the sale of our ownership interests in seven hydroelectric plants in New York. These plants had a combined nameplate capacity of approximately 80 megawatts. In addition, we announced our intention to sell our 40 megawatt gas-fired plant located in Pepperell, Massachusetts.

Power Funds. In addition to our ownership of the power plants described above, we hold various indirect interests in power plants through our investment in energy and energy-related funds, both domestic and international, with a total net capacity of approximately 29 megawatts.

Fund Name	Number of Plants	Total Capacity (MWs)	Interest	Net Capacity (MWs)
Energy Investors Fund I	3	58.3	12.6%	7.4
Energy Investors Fund II	6	66.6	6.9%	4.6
Project Finance Fund III	8	256.0	5.3%	13.6
Caribbean Basin	4	99.3	3.7%	3.7
Total Fund Interests		**480.2**		**29.3**

Project Development Program. Through our active project development program, we are developing and pursuing the acquisition of a number of additional unregulated generation projects, ranging from the expansion of existing generating capacity, or “brownfield development,” to the acquisition or development of new generating facilities. Our primary geographic focus has been, and is likely to remain, in the North American Electric Reliability Council region known as the WECC. Among the factors we consider important in evaluating new or expanded generation opportunities are the following:

- potential electric demand growth in the targeted region;
- regional generation capacity characteristics;
- permitting and siting requirements;
- proximity of the proposed site to high transmission capacity corridors;
- fuel supply reliability and pricing;
- the local regulatory environment; and
- the potential to exploit market expertise and operating efficiencies relating to geographic concentration of new generation with our existing power plant and fuel production portfolio.

Our goal is to sell a substantial majority of the independent power generation portfolio under long-term contracts, while reserving the balance for merchant, or spot, sales. Our strategy is to seek long-term contracts with either utilities serving native customer loads with state utility commission-approved contracts, or investment-grade counterparties. To limit our financial exposure, we typically project finance our unregulated power generation facilities so that the lenders will only have recourse to a specific facility. We cannot assure you that we will be successful in completing any or all of the projects currently under consideration.

Oil and Gas Segment

Our oil and gas segment, which operates primarily through our Black Hills Exploration and Production, Inc. subsidiary, is involved in the acquisition, exploration, development and production of natural gas and crude oil resources. We hold interests in oil and gas properties located in Alabama, California, Colorado, Louisiana, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, Texas and Wyoming and we own and operate a natural gas gathering pipeline in New Mexico. We operate approximately 516 oil and gas wells and also own a working interest in, but do not operate, an additional 480 wells.

We also own a 44.7 percent interest in the Newcastle gas processing plant located in Weston County, Wyoming adjacent to certain of our producing properties in that area.

The majority of our reserves are located in the Rocky Mountain region. Approximately 66 percent of our reserves are located in the San Juan Basin of Northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County and 20 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field area of Weston and Niobrara counties. As of December 31, 2004, natural gas and oil comprise 82 percent and 18 percent of our total proved reserves, respectively. At December 31, 2004 we had total reserves of approximately 173.4 BCFE.

Summary Oil and Gas Reserve Data

The following table sets forth summary information concerning our estimated proved oil and gas reserves and the 10 percent discounted present value of estimated future net revenues as of December 31, 2004, based on a report prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. Reserves were determined using year-end product prices, held constant for the life of the properties. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results.

	December 31, 2004
Proved Reserves:	
Natural gas (MMcf)	141,983
Oil (Mbbl)	5,239
Total (MMcfe)	173,417
Proved Developed Reserves:	
Natural gas (MMcf)	80,366
Oil (Mbbl)	4,608
Total (MMcfe)	108,014
Present value of estimated future net revenues, before tax (in thousands)	$ 394,446

Drilling Activity

The following table reflects our drilling activities of the wells completed for the year ended December 31, 2004. In 2004, we participated in drilling 161 gross (64.3 net) development and exploratory wells, completing 127 gross (43.49 net) wells by year-end, of which 112 gross (36.18 net) wells were successful, and 15 gross (7.31 net) were dry holes. At year end we had 34 gross (20.81 net) wells in progress.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
Wyoming	26	—	26	0.66	—	0.66
New Mexico	15	—	15	14.92	—	14.92
Montana	52	4	56	10.60	0.31	10.91
Other states	19	11	30	10.00	7.00	17.00
Total	112	15	127	36.18	7.31	43.49

Recompletion Activity

The following table reflects our recompletion activities for the year ended December 31, 2004.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
Wyoming	24	—	24	19.36	—	19.36
New Mexico	19	—	19	18.27	—	18.27
Montana	—	—	—	—	—	—
Other states	11	—	11	7.00	—	7.00
Total	54	—	54	44.63	—	44.63

Productive Wells

The following table summarizes our gross and net interests in productive wells at December 31, 2004. Net interests represented in the table are net "working interests" which bear the cost of operations.

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	489	22	511	227.00	3.16	230.16
New Mexico	2	127	129	1.54	94.18	95.72
Montana	2	122	124	0.25	19.89	20.14
Other states	7	123	130	0.78	33.13	33.91
Total	500	394	894	229.57	150.36	379.93

Acreage

The following table summarizes our undeveloped, developed and total acreage by region as of December 31, 2004 (in thousands).

Area	Undeveloped Gross	Undeveloped Net	Developed Gross	Developed Net	Total Gross	Total Net
Wyoming	40	26	20	10	60	36
New Mexico	23	22	17	15	40	37
Montana	570	106	69	10	639	116
Nebraska	3	3	48	45	51	48
Other	47	9	29	10	76	19
Total	683	166	183	90	866	256

For more information on our oil and gas operations, see Note 26 to our Notes to Consolidated Financial Statements.

Coal Mining Segment

Our coal mining segment, which operates through our Wyodak Resources Development Corp. subsidiary, mines and processes low-sulfur, sub-bituminous coal at our Wyodak coal mine near Gillette, Wyoming. The Wyodak mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin, one of the largest coal reserves in the United States. We produced approximately 4.8 million tons of coal in 2004. Mining rights to the coal are based on four federal leases and one state lease. We pay royalties of 12.5 percent and 9.0 percent, respectively, of the selling price on all federal and state coal. As of December 31, 2004, we had coal reserves of approximately 294 million tons, based on an updated internal reserve study completed in 2004. The reserves would be enough to satisfy present contracts for approximately 59 years at current production levels.

Substantially all of our coal production is currently sold under long-term contracts to:

- our electric utility, Black Hills Power;
- the 362 megawatt Wyodak power plant owned 80 percent by PacifiCorp and 20 percent by Black Hills Power;
- PacifiCorp at the Dave Johnston power plant located near Casper, Wyoming, served by rail;
- our unregulated mine-mouth power plant, Wygen; and
- certain industrial customers served by truck.

We also expect to increase our coal production to supply:

- additional mine-mouth generating capacity at the same site as the Wygen plant, which we are in the early stages of developing; and
- future sales of coal to regional rail- and truck-served customers.

Our coal mining segment’s agreement with Black Hills Power limits earnings from all coal sales to Black Hills Power to a specified return on our cost-depreciated investment base. Black Hills Power made a commitment to the South Dakota Public Utilities Commission (SDPUC), the Wyoming Public Service Commission (WPSC) and the City of Gillette that coal would be furnished and priced as provided by that agreement for the life of Black Hills Power’s Neil Simpson II plant, which Black Hills Power placed into service in 1995.

The price for unprocessed coal sold to PacifiCorp for its 80 percent interest in the Wyodak plant is determined by a coal supply agreement terminating in 2022.

Energy Marketing and Transportation Segment

We market natural gas and crude oil in specific regions of the United States and Canada. We offer physical and financial wholesale energy marketing and price risk management products and services to a variety of customers. The customers of our energy marketing and transportation segment include:

- natural gas distribution companies;
- municipalities;
- industrial users;
- oil and gas producers;
- electric utilities;
- other energy marketers; and
- retail gas users.

Our average daily marketing volumes for the year ended December 31, 2004 were approximately 1.7 million MMBtu, or million British thermal units of gas, and 44,900 barrels of oil.

The following table identifies the location of our fuel marketing operations and sales offices:

Company	**Fuel**	**Marketing Operations**	**Satellite Offices**
Enserco Energy Inc.	Natural Gas	Golden, CO	Calgary, Alberta
Black Hills Energy Resources, Inc.	Crude Oil	Houston, TX	Tulsa, OK; Midland, TX; Longview, TX

Enserco Energy Inc. Our natural gas marketing operations focus primarily on producer services, end use origination and wholesale marketing providing marketing services to natural gas producers. Our producer marketing services include purchases of wellhead gas, risk transfer and hedging products for gas producers in the Rocky Mountain region. Our gas marketing efforts are concentrated in the Rocky Mountain, Western and Mid-continent regions of the United States and in Canada. We hold, under contract, natural gas storage capacity and both long- and short-term transportation capacity on several major pipelines in the western and mid-continent regions of the United States and in Western Canada.

Black Hills Energy Resources, Inc. Our crude oil marketing and transportation operations are headquartered in Houston, Texas and are concentrated primarily in Texas, Oklahoma and Louisiana. Our crude oil marketing business specializes in providing independent crude oil producers with marketing and transportation services to market their crude oil production to end-user markets. In addition, we own, operate or lease the following facilities:

Millennium Pipeline System. We own and operate the Millennium Pipeline System, a 200-mile pipeline with a capacity of approximately 65,000 barrels of oil per day. The pipeline transports imported crude oil from Beaumont, Texas to Longview, Texas, a transfer point to connecting carriers. We recently extended the long-term contract for the transport of petroleum products on the Millennium Pipeline System through the third quarter of 2007. Through this long-term contract, the capacity on this pipeline is substantially subscribed.

Millennium Terminal. Through the Millennium Terminal, we lease 1.1 million barrels of crude oil storage at the Oil Tanking terminal located in Beaumont. The Millennium Terminal storage facility is connected to our Millennium Pipeline System.

Kilgore Pipeline System. We also own and operate the Kilgore Pipeline System, a 190-mile pipeline with a capacity of approximately 35,000 barrels per day. The pipeline transports crude oil from Kilgore, Texas south to Houston, Texas, a transfer point to connecting carriers. We have a long-term agreement for the transport of petroleum products on the Kilgore Pipeline that also expires in the third quarter of 2007. Through this long-term contract, the capacity of this pipeline is significantly subscribed. In addition, we have approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas.

Retail Services Group

Electric Utility Segment

Our electric utility, Black Hills Power, is engaged in the generation, transmission and distribution of electricity. It provides us with a solid foundation of revenues, earnings and cash flow.

Distribution and Transmission. Black Hills Power’s distribution and transmission businesses serve approximately 62,000 electric customers, with an electric transmission system of 447 miles of high voltage lines and 263 miles of lower voltage lines. In addition, Black Hills Power jointly owns 43 miles of high voltage lines with Basin Electric Cooperative. Black Hills Power’s service territory covers a 9,300 square mile area of western South Dakota, northeastern Wyoming and southeastern Montana with a strong and stable economic base. Approximately 90 percent of Black Hills Power’s retail electric revenues in 2004 were generated in South Dakota.

The following are characteristics of Black Hills Power’s distribution and transmission businesses:

- We have a diverse customer and revenue base. Our revenue mix for the year ended December 31, 2004 was comprised of 28 percent commercial, 22 percent residential, 14 percent contract wholesale, 23 percent wholesale off-system, 12 percent industrial and 1 percent municipal sales and other revenue. Approximately 73 percent of our large commercial and industrial customers are provided service under long-term contracts. We have historically optimized the utilization of our power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts.
- Black Hills Power is subject to regulation by the South Dakota Public Utilities Commission (SDPUC) and the Wyoming Public Service Commission (WPSC). The retail rate freeze granted to Black Hills Power by the SDPUC, which had been in effect for 10 years, expired on January 1, 2005. Black Hills Power’s current rates in South Dakota and Wyoming remain in place following the expiration of the rate freeze. The rate freeze preserved our low-cost rate structure for our retail customers at levels below the national average while allowing us to retain the benefits from cost savings and from wholesale “off-system” sales, which were not covered by the rate freeze. Our rates do not include a fuel or a purchased power adjustment, so we continue to have the flexibility in allocating our generating capacity to wholesale off-system sales. While we are not obligated to do so, we are permitted to petition the SDPUC and WPSC for a rate increase at any time, or the SDPUC and WPSC may require that we do so. We do not expect to request a rate increase for Black Hills Power during 2005.
- 23 percent of our electric revenues for the year ended December 31, 2004 consisted of off-system and short-term contract wholesale sales.

- Black Hills Power and Basin Electric Power Cooperative completed the construction of an AC-DC-AC transmission tie in the fourth quarter of 2003. Black Hills Power owns 35% and Basin Electric owns 65% of the transmission tie. The transmission tie provides an interconnection between the Western and Eastern transmission grids, enabling access to both the WECC region in the West, and the Mid-Continent Area Power Pool, or "MAPP" region in the East. The Black Hills Power system is located in the WECC region. The total transfer capacity of the tie is 400 megawatts—200 megawatts from West to East and 200 megawatts from East to West. This transmission tie allows us to buy and sell energy in the Eastern interconnection without having to isolate and physically reconnect load or generation between the two electrical transmission grids. The transmission tie is bidirectional and thus accommodates scheduling transactions in both directions simultaneously. This transfer capability provides additional opportunity to sell our excess generation or to make economic purchases to serve our native load and our contract obligations, and to take advantage of the power price differentials between the two electric grids. Additionally, Black Hills Power's system is capable of directly interconnecting up to 80 megawatts of generation or load to the Eastern transmission grid. Transmission constraints within the MAPP transmission system may limit the amount of capacity that may be directly interconnected to the Eastern system at any given time.
- We have firm point-to-point transmission access to deliver up to 17 megawatts of power on PacifiCorp's transmission system to wholesale customers in the Western region from 2004 through 2006 and 50 megawatts from 2007 through 2023.
- We have firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve our power sales contract with Montana-Dakota Utilities Company (MDU) through 2006, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

Power Sales Agreements. We sell a portion of Black Hills Power's current load under long-term contracts. Our key contracts include:

- an agreement with MDU, expiring at the end of 2006, for the sale of up to 55 megawatts of capacity and energy to serve the Sheridan, Wyoming electric service territory. We recently entered into a new power purchase agreement with MDU for the supply of up to 74 megawatts of capacity and energy for Sheridan, Wyoming through 2017, which is pending regulatory approval by the WPSC; and
- an agreement with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy.

These consumers are integrated into Black Hills Power's control area and are treated as firm native load. Black Hills Power also provides 20 megawatts of unit contingent energy and capacity to MEAN under a contract that expires in 2013.

Regulated Power Plants and Purchased Power. Black Hills Power's electric load is primarily served by its generating facilities in South Dakota and Wyoming, which provide 435 megawatts of generating capacity, with the balance supplied under purchased power and capacity contracts. Approximately 50 percent of Black Hills Power's capacity is coal-fired, 39 percent is oil- or gas-fired, and 11 percent is supplied under the following purchased power contracts with PacifiCorp:

- a power purchase agreement expiring in 2023, involving the purchase by Black Hills Power of 50 megawatts of baseload power; and
- a reserve capacity integration agreement expiring in 2012, which makes available to Black Hills Power 100 megawatts of reserve capacity in connection with the utilization of the Ben French CT units.

Since 1995, Black Hills Power has been a net producer of energy. Black Hills Power reached its peak system load of 392 megawatts in August 2001. None of Black Hills Power's generation is restricted by hours of operation, thereby providing it the ability to generate power to meet demand whenever necessary and feasible.

The following table describes Black Hills Power's portfolio of power plants:

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Ben French	Coal	SD	25.0	100%	25.0	1960
Ben French Diesels 1-5	Diesel	SD	10.0	100%	10.0	1965
Ben French CTs 1-4	Gas/Oil	SD	100.0	100%	100.0	1977-1979
Lange CT	Gas	SD	40.0	100%	40.0	2002
Neil Simpson I	Coal	WY	21.8	100%	21.8	1969
Neil Simpson II	Coal	WY	91.0	100%	91.0	1995
Neil Simpson CT	Gas	WY	40.0	100%	40.0	2000
Osage	Coal	WY	34.5	100%	34.5	1948-1952
Wyodak	Coal	WY	362.0	20%	72.4	1978
Total			724.3		434.7	

Ben French. Ben French is a wholly owned coal-fired plant located in Rapid City, South Dakota, with a capacity of 25 megawatts. This plant was put into service in 1960 and has since been operating as a baseload plant. The plant purchases coal from our Wyodak mine, which is delivered by truck.

Ben French Diesel Units 1-5. The Ben French Diesel Units 1-5 are wholly owned diesel-fired plants located in Rapid City, South Dakota, with an aggregate capacity of 10 megawatts. These plants were placed into service in 1965, and operate as peaking plants.

Ben French CTs 1-4. The Ben French Combustion Turbines 1-4 are wholly owned gas- and/or oil-fired units with an aggregate capacity of 100 megawatts located in Rapid City, South Dakota. These facilities were placed into service from 1977 to 1979, and operate as peaking units.

Lange CT. The Lange Combustion Turbine is a wholly owned 40 megawatt gas-fired plant located near Rapid City, South Dakota. The plant was placed into service in 2002 and provides peaking capacity and voltage support for the area.

Neil Simpson I and II. Neil Simpson I and II are wholly owned, air-cooled, coal-fired facilities located near Gillette, Wyoming. Neil Simpson I has a capacity of 21.8 megawatts and was placed into service in 1969. Neil Simpson II has a capacity of 91 megawatts and was placed into service in 1995. These plants operate as baseload facilities, and are mine-mouth plants, receiving their coal directly from our Wyodak mine.

Neil Simpson CT. The Neil Simpson Combustion Turbine is a wholly owned gas-fired plant located near Gillette, Wyoming with a capacity of 40 megawatts. This plant was placed into service in 2000, and provides peaking capabilities.

Osage. The Osage plant is a wholly owned coal-fired plant in Osage, Wyoming with a total capacity of 34.5 megawatts. This plant, which was placed into service from 1948 to 1952, has three turbine generating units and operates as a baseload plant. The plant purchases coal from our Wyodak mine, which is delivered by truck.

Wyodak. Wyodak is a 362 megawatt mine mouth coal-fired plant owned 80 percent by PacifiCorp and 20 percent (or 72.4 net megawatts) by Black Hills Power. Our Wyodak mine furnishes all the coal fuel supply for the Wyodak plant. The plant was placed into service in 1978 and operates as a baseload plant.

Communications Segment

Our communications segment, which primarily operates through our subsidiary Black Hills FiberCom, was formed to provide state-of-the-art broadband telecommunications services to the markets of Rapid City and the northern Black Hills of South Dakota. We offer residential and business customers broadband telecommunications services, including local and long distance telephone service, expanded cable television service, cable modem Internet access and high speed data and video services. We have completed a 245-mile inter- and intra-city fiber optic network and currently operate 845 miles of two-way interactive hybrid fiber coaxial or “HFC” cable. We bundle these services into value packages with a single consolidated bill for all of these services.

We introduced our broadband communications services to the Rapid City and northern Black Hills areas in November 1999. As of December 31, 2004, we were serving 23,663 residential customers and 3,317 business customers.

The construction of our initial infrastructure build-out, which covers much of Rapid City and the northern Black Hills region, was completed in 2002. While we continue to modestly increase the system, we are currently focused on achieving operating efficiencies, both internal to our communications group and those that can be realized by integrating appropriate business functions with related utility operations in our retail business group and at the corporate or service company level.

Combination Electric and Gas Utility Segment

We acquired CLF&P in January 2005, and we will report its operations as a new segment within the retail services group in future SEC filings.

Electric System. CLF&P’s electric system serves approximately 38,000 customers in Cheyenne, Wyoming and vicinity, and has a peak load of 163 megawatts. Power is supplied to CLF&P under an all-requirements contract with PSCo. The all-requirements contract expires in 2007.

Natural Gas System. CLF&P’s natural gas distribution system serves approximately 31,000 natural gas customers in Cheyenne, Wyoming and vicinity. CLF&P’s annual natural gas sales and transportation during 2004 were approximately 13.6 million MMbtus, with sales to commercial and residential customers accounting for approximately 4.4 million MMbtus and transportation accounting for approximately 9.2 million MMbtus.

CLF&P purchases natural gas from independent suppliers. The natural gas supplies are delivered to the respective delivery systems through a combination of transportation agreements with interstate pipelines and deliveries by suppliers directly to each company. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at CLF&P’s city gate meter station and a small amount is received directly from wellhead sources.

Competition

The independent power, fuel production and energy marketing industries are characterized by numerous strong and capable competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than us.

The Federal Energy Regulatory Commission, or FERC, has implemented and continues to favor regulatory initiatives to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity and to enhance competition in wholesale electricity markets. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses, and deregulation initiatives in a number of states may encourage further disaggregation. However, the pace of restructuring slowed significantly following public and governmental reactions to issues associated with deregulation efforts in California and the collapse of its wholesale electric energy market in 2001. Retail competition has not yet been implemented in South Dakota, Wyoming, or Montana.

In addition, Congress in recent years has considered various legislative proposals to restructure the electric industry that would require, among other things, customer choice and/or repeal of PUHCA. The debate is likely to continue and perhaps intensify. We cannot predict the likelihood or effect of such legislation with any degree of certainty. As a result of these potential regulatory changes, significant additional competitors could become active in the generation and power marketing segments of our industry.

Our communications unit faces strong competition from several companies, including Qwest Corporation, Rapid City's incumbent local exchange carrier and Midcontinent Communications, the area's incumbent cable television provider, as well as long distance providers, cellular providers, satellite providers and Internet service providers. Our success in this business will depend upon, among other things, the quality of our customer service, the willingness of residential and business customers to accept us as an alternative provider of broadband communications products and services and our ability to offer an attractive package of bundled products.

Risk Management

Our business operations require effective management of price, counterparty performance and operational risks. Price risk arises from the volatility of energy prices. Counterparty performance risk is the risk that a counterparty will fail to satisfy its contractual obligations to us, and includes credit risk. Operational risk is the risk that we will be unable to perform on our contractual obligations to our counterparties. We have implemented controls to mitigate each of these risks.

Our energy marketing operations are conducted in accordance with guidelines established through separate risk management policies and procedures for each marketing company and through our credit policy and procedures. These policies and procedures specify maximum price risk exposure levels within which each respective marketing company must operate. These policies are established and approved by our executive risk committee and reviewed by our board of directors. The policies are reviewed on a regular basis and monitored as described below.

We have an active risk management committee, which oversees each of our marketing companies, and a credit committee, which oversees credit for the entire corporate organization. The risk management committee focuses on implementation of risk management procedures and on monitoring compliance with established policies. The credit committee monitors credit exposure levels and reviews compliance with established credit policies. Our Chief Risk Officer is responsible for overseeing these functions.

We further limit the exposure of our parent holding company, Black Hills Corporation, to energy marketing risks by maintaining separate credit facilities within each of our energy marketing companies. These credit facilities have security interests solely against the assets of the respective marketing company. In addition, we limit the number and amount of any parent guarantees for the marketing companies.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. Short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risks, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities exceed our anticipated load requirements plus a required reserve margin.

Regulation

We are subject to a broad range of federal, state and local energy and environmental laws and regulations applicable to the development, ownership and operation of our projects, and our utility operations are subject to federal and state rate regulation. These laws and regulations generally require that a wide variety of permits and other approvals be obtained before construction or operation of a project commences and that, after completion, the facility operate in compliance with such requirements. Our public utilities operate subject to tariffs and rate schedules that must be filed with, and accepted by, state and federal regulatory commissions. We strive to comply with the terms of all such laws, regulations, permits, licenses, rate schedules, and tariffs and believe that all of our operations are in material compliance with all such applicable requirements.

Energy Regulation

Public Utility Holding Company Act of 1935. As a registered holding company, we are subject to regulatory oversight by the SEC under PUHCA. The rules and regulations under PUHCA impose a number of restrictions on the operations of registered holding company systems. These restrictions include, subject to certain exceptions, a requirement that the SEC approve securities issuances, payments of dividends out of capital or unearned surplus, sales and acquisitions of utility assets or of securities of utility companies, and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company to a single integrated public utility system, plus additional energy-related and other approved businesses. PUHCA rules require that members of a holding company system obtain certain common services, such as accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, and so we have formed Black Hills Services Company, LLC, as a services company for the Black Hills Corporation system. PUHCA rules also require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions. Registered holding companies are subject to accounting, record-keeping and periodic reporting requirements administered by the SEC.

Federal Power Act. The Federal Power Act gives FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC’s jurisdiction are required to file tariffs and rate schedules with FERC prior to commencement of wholesale sales or interstate transmission of electricity. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their unregulated affiliates.

The Energy Policy Act. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing certain exemptions from regulation for exempt wholesale generators, or EWGs. An EWG is an entity that is directly or indirectly, and exclusively, in the business of owning or operating, or both owning and operating, eligible facilities and selling electric energy at wholesale. An EWG is not regulated as an electric utility under PUHCA, but is subject to FERC regulation, including rate regulation. All of our non-utility subsidiaries that would otherwise be treated as electric utilities under PUHCA are currently treated as EWGs under the Energy Policy Act or QFs under PURPA. All of our EWGs have been granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates. However, FERC customarily reserves the right to suspend, upon complaint, market-based rate authority on a prospective basis if it is subsequently determined that any of our EWGs exercised market power. If FERC were to suspend market-based rate authority for any of our EWGs, those EWGs most likely would be required to file, and obtain FERC acceptance of, cost-based power sales rate schedules. Also, the loss of market-based rate authority would subject the EWGs to the accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

In addition, if there occurs a “material change” in facts that might affect any of our subsidiaries’ eligibility for EWG status, within 60 days of the material change, the relevant EWG must (1) file a written explanation of why the material change does not affect its EWG status, (2) file a new application for EWG status, or (3) notify FERC that it no longer wishes to maintain EWG status. If any of our subsidiaries were to lose EWG status, we likely would be subject to additional layers of regulation under PUHCA.

PURPA. The enactment of PURPA in 1978 provided incentives for the development of qualifying cogeneration facilities and small power production facilities that utilized certain alternative or renewable fuels (QFs). QF status conveys two primary benefits. First, regulations under PURPA exempt QFs from PUHCA, most provisions of the Federal Power Act and the state laws concerning rates, and financial and organizational regulations of electric utilities. Second, FERC’s regulations under PURPA require that (1) electric utilities purchase electricity generated by QFs at a price based on the purchasing utility’s full avoided cost of producing power, (2) the electric utilities must sell back-up, interruptible, maintenance and supplemental power to the QF on a non-discriminatory basis, and (3) the electric utilities must interconnect with any QF in its service territory, and, if required, transmit power if they do not purchase it. We operate our Las Vegas I and Ontario facilities as QFs. We endeavor to acquire, develop and operate our QFs in a manner that minimizes the risk of those plants losing their QF status. However, if a facility were to lose QF status, we could attempt to avoid its regulation as an additional public utility company in our registered holding company system under PUHCA by qualifying the project as an EWG.

State Energy Regulation. In areas outside of wholesale rate regulation (such as financial or organizational regulation), some state utility laws may give their public utility commissions broad jurisdiction over steam sales or EWGs that sell power in their service territories. The actual scope of the jurisdiction over steam or independent power projects depends on state law and varies significantly from state to state.

Retail Rate Regulation

***Black Hills Power*.** The rate freeze granted by the SDPUC, which had been in effect for Black Hills Power since 1995, expired on January 1, 2005. During this ten-year term, Black Hills Power was prohibited, subject to certain limited exceptions, from filing for any increase in its rates or invoking any fuel and purchased power adjustment tariff which would take effect during the freeze period. While the rate freeze has expired, Black Hills Power cannot raise rates without initiating a proceeding before the SDPUC and the WPSC and receiving approval from these commissions. As such, Black Hills Power’s current rates remain in effect.

Unless and until Black Hills Power files for and receives a rate increase, it is undertaking the risks of:

- machinery failure;
- load loss caused by either an economic downturn or changes in regulation;
- costs of fuel commodities;
- increased costs under power purchase contracts over which it has no control;
- government interferences; and
- acts of nature and other unexpected events that could cause material losses of income or increases in costs of doing business.

Under its current structure, however, Black Hills Power will continue to retain earnings realized from more efficient operations, sales from load growth, and off-system sales of power and energy.

Beginning in the mid-1990’s, we initiated an effort to enter into new contracts with our largest commercial and industrial customers. Most of the new contracts contain “meet or release” provisions that grant us a five-year right to continue to serve a customer at market rates in the event of deregulation. Additionally, through our General Service Large Optional Combined Account Billing Tariff, we have allowed general service customers to aggregate their loads. This tariff also provides us with a five-year right to continue to serve those customers in the event of deregulation. Our “meet or release” contracts currently total more than 110 megawatts of large commercial and industrial load. These contracts provide us with greater assurance of a firm local market for our power resources in the event deregulation occurs. These industrial and large commercial customers, together with our wholesale power sale agreements with the City of Gillette, Wyoming and MDU, equal approximately 50 percent of Black Hills Power’s firm load.

CLF&P. Our CLF&P electric and natural gas distribution utility, which we acquired in January 2005, is subject to the jurisdiction of the WPSC with respect to its facilities, rates, accounts, services and issuance of securities. CLF&P is subject to the jurisdiction of FERC with respect to accounting practices and the transmission of electricity in interstate commerce. All electric demand and purchased power costs are recoverable through an energy adjustment clause subject to WPSC jurisdiction. All purchased gas costs are recoverable through a gas cost adjustment clause, also subject to WPSC jurisdiction. Differences in costs incurred from costs recovered in rates, including interest, are deferred and recovered through prospective adjustments to rates. Rate changes for cost recovery require WPSC approval before going into effect. As part of obtaining approval from the WPSC for the acquisition of CLF&P, we agreed that CLF&P would be barred from increasing its retail rates prior to January 1, 2006, other than pursuant to gas and electric cost adjustments. However, we plan to cause CLF&P to file a rate case during 2005 for rates to be effective on or soon after January 1, 2006.

Environmental Regulation

The construction and operation of power projects, coal mines, oil and gas exploration and production, gas transportation and crude oil handling facilities are subject to extensive environmental protection and land use regulation in the United States. These laws and regulations often require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies. If such laws and regulations are changed and our facilities are not grandfathered, extensive modifications to project technologies and facilities could be required.

General. Based on current trends, we expect that environmental and land use regulation will continue to be stringent. Accordingly, we actively review proposed construction projects that could subject us to stringent pollution controls imposed on “major modifications,” as defined under the Clean Air Act, and changes in “discharge characteristics,” as defined under the Clean Water Act. The goal of these actions is to achieve compliance with applicable regulations, administrative consent orders and variances from applicable air-quality related regulations.

Air Quality. Our Neil Simpson II, Neil Simpson CT, Gillette CT, Wygen, Arapahoe, Valmont, Fountain Valley, Las Vegas II, Lange CT and Wyodak plants are all subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold sulfur dioxide (SO2) “allowances” for each ton of sulfur dioxide emitted. We currently hold sufficient allowances credited to us as a result of sulfur removal equipment previously installed at the Wyodak plant to apply to the operation of all units subject to Title IV through 2034 without requiring the purchase of any additional allowances. With respect to any future plants, we plan to comply with the need for holding the appropriate number of allowances by reducing sulfur dioxide emissions through the use of low sulfur fuels, installation of “back end” control technology, use of banked allowances left over from our unused portion of Wyodak allowances and if necessary, the purchase of allowances on the open market. We expect to integrate the costs of obtaining the required number of allowances needed for future projects into our overall financial analysis of such projects.

In July 1999, the United States Environmental Protection Agency (EPA) finalized rules designed to protect and improve visibility impairment resulting from air emissions. Among other things, the regulations required states to identify sources of emissions (including certain coal-fired generating units built between 1962 and 1977) by 2004 that would be subject to “Best Available Retrofit Technology,” known as BART. These sources would be required to implement BART within five years after the EPA approves state plans adopted to combat visibility impairment. Subsequent litigation has removed EPA’s requirement mandating that states adopt and impose BART requirements; however, it remains an option for states to use in addressing visibility impairment. We believe our only existing plant which may be required to comply with the BART requirements is our Neil Simpson I plant in Wyoming. Late in 2003, the State of Wyoming elected to manage visibility impairment through 40 CFR Part 51.309 (Grand Canyon Visibility Transport States), or the 309 program. Under this program, there is a Backstop SO2 Emission Trading Program that eliminates the need for BART in the states that opt into the 309 program. Therefore, Neil Simpson I will not have to implement BART controls, but all of our plants will fall under the Backstop SO2 Emission Trading Program if it is triggered to be implemented. The trading program would be triggered if annual SO2 emission reductions do not remain in a declining trend. After discussions with Wyoming regulatory staff, we believe this program will not have a material adverse effect on our financial position or results of operations. We are aware of a February 18, 2005 decision by the United States Court of Appeals for the District of Columbia Circuit that grants a petition for review of this rule. Until this issue is ultimately resolved, we are unable to evaluate its impact. We are aware that other states in which we have power plants are required to submit their visibility impairment plans to EPA between 2004 and 2008 and that compliance is due within five years of EPA approval. We believe that any capital expenditures associated with future compliance requirements would not have a material adverse effect on our financial position or results of operations.

Title V of the Clean Air Act imposes federal requirements, which dictate that all of our fossil fuel-fired generation facilities must obtain operating permits. All of our existing facilities subject to this requirement have submitted Title V permit applications and either have received or are in the process of receiving permits.

On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act’s “new source review” (NSR) requirements related to modifications of air emissions sources at electric generating stations located in the southern and midwestern regions of the United States. Several states joined these lawsuits. In addition, the EPA has also issued administrative notices of violation alleging similar violations at additional power plants owned by some of the same utilities named as defendants in the Department of Justice lawsuit. The EPA has also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities seeking to determine whether those utilities also engaged in activities that may have been in violation of the Clean Air Act’s NSR requirements. In May 2003, the EPA notified PacifiCorp that it is investigating similar activities at their Wyodak Plant, in which we hold a 20 percent ownership interest. We are receiving copies of all information provided to EPA. At this time no legal proceedings have commenced. No such NSR proceedings have been initiated or requests for information issued with respect to any of our other facilities, but we cannot assure you that we will not be subject to similar proceedings in the future.

In December 2000, the EPA announced its intention to regulate mercury emissions from coal- and oil-fired electric power plants. In December 2003, the EPA issued proposed rules and solicited comments on regulatory options for regulating mercury. Final rules are expected in March 2005. However, there is also action in Congress regarding the Administration’s Clear Skies package, which may alter the EPA’s mercury rulemaking process by implementing a cap and trade program. Until these efforts are finalized, we are not able to fully evaluate the impact of mercury regulations on the operation of our facilities.

Since the adoption of the United Nations Framework on Climate Change in 1992, there has been worldwide attention with respect to greenhouse gas emissions, in particular carbon dioxide. In December 1997, the Clinton administration participated in the Kyoto, Japan negotiations, where the basis of a climate change treaty was formulated. Under the treaty, known as the Kyoto Protocol, the United States would be required, between 2008 and 2012 to reduce its greenhouse gas emissions by 7 percent from 1990 levels. The treaty has never been ratified by the United States, although discussions continue regarding climate change issues. Although legislative developments on the state level related to controlling greenhouse gas emissions have occurred, we are not aware of any similar developments in the states in which we operate. If we should become subject to limitations on emissions of carbon dioxide from our power plants, these requirements could have a significant impact on our operations.

Clean Water Act. Our existing facilities are also subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under authority of the Clean Water Act and govern overall water/wastewater discharges through National Pollutant Discharge Elimination System, or NPDES, permits. Under current provisions of the Clean Water Act, existing NPDES permits must be renewed every five years, at which time permit limits are extensively reviewed and can be modified to account for changes in regulations or program initiatives. In addition, the permits have re-opener clauses which allow the permitting authority (which may be the United States or an authorized state) to attempt to modify a permit to conform to changes in applicable laws and regulations. Some of our existing facilities have been operating under NPDES permits for many years and have gone through one or more NPDES permit renewal cycles. All of our facilities required to have NPDES permits have those permits in place and are in compliance with discharge limitations. There are no proposed regulations that we are aware of that will have a significant impact on our operations. The stream that receives discharges from the Ben French Plant is expected to be re-classified within the next few years. If that occurs, we expect that discharge limits will become more restrictive. At this time we are unable to assess those impacts until more information is known. Additionally, the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations. All facilities regulated under this program have their required plans in place.

Solid Waste Disposal. We dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Each disposal site has been permitted by the state of its location in compliance with law. Ash and wastes from flue gas and sulfur removal from the Wyodak, Wygen, Neil Simpson I, Ben French and Neil Simpson II plants are deposited in mined areas at our Wyodak coal mine. These disposal areas are located below some shallow water aquifers in the mine. None of the solid wastes from the burning of coal is classified as hazardous material, but the wastes do contain minute traces of metals that would be perceived as polluting if such metals leached into underground water. Investigations have concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we cannot assure you that no pollution will occur over time. In this event, we could experience material costs to mitigate any resulting damages. Agreements in place require PacifiCorp to be responsible for any such costs that would be related to the solid waste from its 80 percent interest in the Wyodak plant.

Additional unexpected material costs could also result in the future if any regulator determines that solid waste from the burning of coal contains some hazardous material that requires special treatment, including solid waste of which we previously disposed. In that event, the government regulator could consequently hold those entities that disposed of such waste responsible for such treatment.

Pipeline Operations. The operations of pipelines and other facilities for gathering, transporting, processing or storing natural gas and crude oil is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with federal, state and local laws that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. Costs of constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws, regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures.

Mine Reclamation. Under federal and state laws and regulations, we are required to submit to the regulation by, and receive approval from, the Wyoming Department of Environmental Quality (DEQ) for a mining and reclamation plan which provides for orderly mining, reclamation and restoration of our entire Wyodak coal mine in conformity with state laws and regulations. We have an approved mining permit and are otherwise in compliance with other permitting programs administered by various regulatory agencies.

Based on extensive reclamation studies, we have accrued approximately $15.9 million on our accompanying Consolidated Balance Sheets for these reclamation costs. No assurance can be given that additional requirements in the future will not be imposed that would cause an unexpected material increase in reclamation costs.

One situation that could result in substantial unexpected increases in costs relating to our reclamation permit concerns three depressions—the “South” depression, the “Peerless” depression and the “Clovis Pit” depression—that have or will result from our mining activities at the Wyodak mine. Because of the thick coal seam and relatively shallow overburden, the current restoration plan would leave these depressions, which have limited reclamation potential, with interior drainage only. Although the DEQ has accepted the current plan to limit reclamation of these depressions, it has reserved the right to review and evaluate future reclamation plans or to reevaluate the existing reclamation plan. If as a result of our mining activities, additional overburden becomes available, the DEQ may require us to conduct additional reclamation of the depressions, particularly if the DEQ finds that the current limited reclamation is resulting in exceedances in the DEQ’s water quality standards.

Ben French Oil Spill. In 1990 and 1991, we discovered extensive underground fuel oil contamination at the Ben French plant site. With the help of expert consultants, we worked closely with the South Dakota Department of Environment and Natural Resources to assess and remediate the site. Our assessment, remediation and site monitoring efforts continue today. All of our underground oil-carrying facilities from which the contamination occurred are now above ground. There have been no significant recoveries of free fuel oil product since 1994. Soil borings and monitoring wells on the perimeters of our Ben French plant property provide no indication of contamination beyond the property’s limits. We believe that the underground spill has been sufficiently remedied so as to prevent any oil from migrating off site. However, due to underground gypsum deposits in this area, the fuel oil has the potential of migrating to area waterways. In such event, cleanup costs could be greatly increased. We believe that sufficient remediation efforts to prevent such a migration are currently in place, but due to the uncertainties of underground geology, we cannot assure you that no such migration will occur.

Cleanup costs recognized to date total approximately $0.5 million, of which amount $0.4 million has been reimbursed by the South Dakota Petroleum Release Compensation Fund. To date, no penalties, claims or actions have been taken or threatened against us because of this oil spill. In 2002, the South Dakota Department of Environment and Natural Resources permanently closed numerous monitoring wells which showed no contamination for several years.

PCBs. Under the federal Toxic Substances Control Act, the EPA has issued regulations that control the use and disposal of polychlorinated biphenyls, or PCBs. PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the Toxic Substances Control Act prohibited any further manufacture of PCB equipment. We remove and dispose of PCB-contaminated equipment in compliance with law as it is discovered.

Release of PCB-contaminated fluids, especially any involving a fire or a release into a waterway, could result in substantial cleanup costs. Several years ago, we began a testing program of potential PCB-contaminated transformers, and in 1997 completed testing of all transformers and capacitors which are not located in our electric substations. We have not completed the testing of sealed potential transformers and bushings located in our electric substations as the testing of this equipment requires their destruction. Release of PCB-contaminated fluid, if present, from our equipment is unlikely and the volume of fluid in such equipment is generally less than one gallon. Moreover, any release of this fluid would be confined to our substation site.

Regulation of Natural Gas and Crude Oil Exploration and Production

Our oil and gas exploration and production operations are subject to various types of regulation at the federal, state and local levels. They include:

- requiring permits for the drilling of wells;
- maintaining bonding requirements in order to drill or operate wells;
- submitting and implementing spill prevention plans;
- submitting notification relating to the presence, use and release of certain contaminants incidental to oil and gas operations, as required under EPA Emergency Planning and Community Right to Know Act (EPCRA) regulations;
- regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities;
- submitting air permit applications for agency review and possible issuance of operating permits;
- compliance with EPA Resource Conservation and Recovery Act (RCRA) requirements; and
- regulating surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production.

Our operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a unit and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, certain state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill. In addition, various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants and the protection of public health, natural resources, wildlife and environment affect our exploration, development and production operations and our related costs.

Other Properties

In addition to the other properties described herein, we own an eight-story office building in Rapid City, South Dakota with approximately 47,000 square feet, of which we occupy approximately 75 percent and lease the remainder to others. Also in Rapid City, we own two additional office buildings consisting of an aggregate of approximately 48,000 square feet and two warehouse buildings consisting of an aggregate of approximately 35,700 square feet. In Cheyenne, Wyoming, we own a business office with approximately 13,356 square feet, and a service center and garage with an aggregate of approximately 28,271 square feet. We lease an aggregate of 36,182 square feet of office space in Golden, Colorado.

Employees

At February 28, 2005, we had 926 full-time employees. We have experienced no labor stoppages or significant labor disputes at our facilities. The following table sets forth the number of employees by business:

	Number of Employees
Corporate(1)	122
Wholesale Energy Group	280
Black Hills Power(2)	283
CLF&P(3)	84
Communications	157
Total	926

(1) These employees are currently employed by Black Hills Corporation. In connection with our registration as a holding company under PUHCA, most of these employees will be transferred to Black Hills Services Company, LLC, the service company we formed to comply with the rules, regulations and orders of the SEC under PUHCA.

(2) Approximately 52 percent of our Black Hills Power employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers (Local 1250), which expires on March 31, 2006.

(3) Approximately 71 percent of our CLF&P employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers (Local 111), which expires on June 30, 2008.

Risk Factors

The following specific risk factors and other risk factors that we discuss in our periodic reports filed from time to time with the SEC should be considered for a better understanding of our Company. These factors and other matters discussed herein are important factors that could cause our actual results or outcomes to differ materially from those discussed in the forward looking statements included elsewhere in this document.

We must rely on cash distributions from our subsidiaries to make debt payments. PUHCA restricts our subsidiaries' ability to pay dividends to us, and there may be changes in the regulatory environment that restrict future dividends from our subsidiaries.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Consequently, our operating cash flow and our ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any contractual or regulatory restrictions that may be applicable to it, which may include requirements to maintain minimum levels of cash, working capital or debt service funds.

Our utility operations are regulated by utility commissions in the States of South Dakota, Wyoming and Montana. These commissions generally possess broad powers to ensure that the needs of the utility customers are being met and that we maintain a reasonable capital structure. As a result of the energy crisis in California and the financial troubles at a number of energy companies, some state utility commissions have imposed restrictions on the ability of the utilities they regulate to pay dividends or make advances to their parent holding companies. If the utility commissions in South Dakota or Wyoming choose to adopt similar restrictions, our utilities' ability to pay dividends or advance funds to us would be limited, which could materially and adversely affect our ability to meet our financial obligations.

Additionally, PUHCA, with limited exception, only permits the payments of dividends to us by our utility subsidiaries out of earned surplus. The SEC has authorized our non-utility subsidiaries to pay dividends out of capital or unearned surplus only where our non-utility subsidiary:

- has received excess cash as a result of the sale of some or all of its assets;
- has engaged in a restructuring or reorganization; and/or
- is returning capital to an associate company.

We cannot assure you that our results from the acquisition and integration of CLF&P will conform to our expectations. There may be additional risks associated with the operation of CLF&P.

We cannot assure you that our actual results from the acquisition of CLF&P will match our expectations. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control and are inherently uncertain. Factors which may cause our actual results to differ materially from our expected results include:

- the actions of the WPSC in response to CLF&P's pursuit of cost recovery in gas and electric cost adjustment filings and other rate proceedings;
- the loss of CLF&P management or key personnel;
- the diversion of our management's attention from other business segments; and
- labor issues associated with CLF&P's union contract.

Our agreements with counterparties that have experienced downgrades in their credit ratings expose us to the risk of counterparty default, which could adversely affect our cash flow and profitability.

We are exposed to credit risks in our power generation, distribution and energy marketing operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. In the past several years, a substantial number of energy companies have experienced downgrades in their credit ratings, some of which serve as our counterparties from time to time. In particular, the credit rating of the senior unsecured debt of Nevada Power Company, a counterparty under tolling and QF agreements with our subsidiaries, is non-investment grade. In addition, we have project level financing arrangements in place that provide for the potential acceleration of payment obligations in the event of nonperformance by a counterparty under related power purchase agreements. If these or other counterparties fail to perform their obligations under their respective power purchase agreements, our financial condition and results of operations may be adversely affected. We may not be able to enter into replacement power purchase agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement power purchase agreements, we would sell the plant's power at market prices.

Our credit ratings could be lowered below investment grade in the future. If this were to occur, our access to capital and our cost of capital and other costs would be negatively affected.

Our issuer credit rating is Baa3 by Moody’s Investor Services, Inc., or Moody’s, and BBB- by Standard & Poor’s Rating Service. Any reduction in our ratings by Moody’s or Standard & Poor’s would reduce our credit rating to non-investment grade status, and such reduction could adversely affect our ability to refinance or repay our existing debt and to complete new financings on acceptable terms or at all.

In addition, a further downgrade in our credit rating would increase our costs of borrowing under some of our existing debt obligations, including borrowings made under our revolving credit facilities, our $128.3 million Wygen plant project financing, and our $24.2 million and $4.0 million secured financings.

A downgrade could also result in our business counterparties requiring us to provide additional amounts of collateral under existing or new transactions.

Geopolitical tensions may impair our ability to raise capital and limit our growth.

Continuing conflict in Iraq or further tensions with the governments of Iran or North Korea could disrupt capital markets and make it more costly or temporarily impossible for us to raise capital, thus hampering the implementation of our stated strategy. In the past, geopolitical events, including the uncertainty associated with the Gulf War in 1991 and the terrorist attacks of September 11, 2001, have been associated with general economic slowdowns. Geopolitical tensions or other factors could retard economic growth and reduce demand for the power and fuel products that we produce or market, which could adversely affect our earnings.

Our utilities may not raise their retail rates without prior approval of the South Dakota Public Utilities Commission or the Wyoming Public Services Commission. If either utility seeks rate relief, it could experience delays in obtaining approvals and could have rate recovery disallowed in rate proceedings.

Our rate freeze agreement with the SDPUC for our Black Hills Power electric utility expired on January 1, 2005. Until such time as we petition the SDPUC or the WPSC for rate relief, or either commission requires that we do so, neither Black Hills Power nor CLF&P may increase its retail rates. Additionally, Black Hills Power may not invoke any fuel and purchased power adjustment tariff that would take effect prior to the completion of a rate proceeding, absent extraordinary circumstances. As part of the process for obtaining approval to acquire CLF&P, we agreed with the WPSC that CLF&P and Black Hills Power would not raise retail rates for their respective Wyoming customers prior to January 1, 2006. Because our utilities are generally unable to increase their base rates without prior approval from the SDPUC and the WPSC, our returns could be threatened by plant outages, machinery failure, increases in purchased power costs over which our utilities have no control, acts of nature, acts of terrorism or other unexpected events that could cause operating costs to increase and operating margins to decline. Moreover, in the event of unexpected plant outages or machinery failures, Black Hills Power may be required to purchase replacement power in wholesale power markets at prices that exceed the rates it is permitted to charge its retail customers. Finally, our utilities’ costs would be subject to the review of the SDPUC or the WPSC, and the commissions could find certain costs not to be recoverable, thus negatively affecting our revenues.

Because prices for our products and services and other operating costs for our business are volatile, our revenues and expenses may fluctuate.

A substantial portion of our net income in recent years has been attributable to sales of wholesale electricity and natural gas into a robust market. The prices of energy products in the wholesale power markets have stabilized at lower levels after the price volatility experienced in the second half of 2000 and the first half of 2001. Power prices are influenced by many factors outside our control, including:

- fuel prices;
- transmission constraints;
- supply and demand;
- weather;
- economic conditions; and
- the rules, regulations and actions of the system operators in those markets.

Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

The success of our oil and gas operations will depend somewhat upon the prevailing market prices of oil and natural gas. Historically, oil and natural gas prices and markets have also been volatile, and they are likely to continue to be volatile in the future. A decrease in oil or natural gas prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. A decline in fuel price volatility could also affect our revenues and returns from energy marketing, which historically tend to increase when markets are volatile.

Our broadband communications business is subject to significant competition for its services and to rapid technological change.

Our communications segment, which provides a suite of communication services, faces strong competition for its services from the incumbent local exchange carrier and from long distance providers, cellular providers, satellite providers, Internet service providers, the incumbent cable television provider and others.

Our ability to recover our capital investment is dependent on our ability to sustain our customer base and is subject to the risk that technological advances may render our network obsolete. If we determine that we will be unable to recover our investment, we would be required to take a non-cash charge to earnings in an amount that could be material in order to write down a portion of our investment in our broadband communications business.

Construction, expansion, refurbishment and operation of power generating and transmission and resource recovery facilities involve significant risks which could lead to lost revenues or increased expenses.

The construction, expansion, refurbishment and operation of power generating and transmission and resource recovery facilities involve many risks, including:

- the inability to obtain required governmental permits and approvals;
- the unavailability of equipment;
- supply interruptions;
- work stoppages;
- labor disputes;
- social unrest;
- weather interferences;
- unforeseen engineering, environmental and geological problems; and
- unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, especially in the case of newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses, higher maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, and our rights under warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damage payments.

Our power project development, expansion and acquisition activities may not be successful, which would impair our ability to execute our growth strategy.

The growth of our independent power business through development, expansion and acquisition activities is important to our future growth. We may not be able to continue to develop attractive opportunities or to complete acquisitions or development projects we undertake. Factors that could cause our activities to be unsuccessful include:

- competition;
- the trend of utilities building their own generation or looking for developers to develop and build projects for sale to utilities under turnkey arrangements;
- lower than anticipated increases in the demand for power in our target markets;
- fuel prices or fuel supply constraints;
- transmission constraints;
- changes in federal or state laws and regulations;
- our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- our inability to obtain financing on acceptable terms, or at all;
- our inability to obtain required governmental permits and approvals;
- capital market conditions; and
- our inability to successfully integrate any businesses we acquire.

Estimates of the quantity and value of our proved oil and gas reserves may change materially due to numerous uncertainties inherent in estimating oil and natural gas reserves.

There are many uncertainties inherent in estimating quantities of proved reserves and their values. The process of estimating oil and natural gas reserves requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretations and judgment, and the assumptions used regarding quantities of recoverable oil and gas reserves and prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and these variances may be significant. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from our estimates. In addition, results of drilling, testing and production and changes in oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three dimensional structural modeling.

There are many uncertainties inherent in estimating quantities of coal reserves. The process of coal volume estimation requires interpretations of drill hole log data and subsequent computer modeling of the intersected deposit. Any significant inaccuracies in these interpretations or modeling could materially affect the quantity and quality of our reserves. The accuracy of reserve estimates is a function of engineering and geological interpretations and judgment of known data, assumptions used regarding structural limits and mining extents, conditions encountered during actual reserve recovery, and undetected deposit anomalies. Variance from the assumptions used and drill hole modeling density could result in additions or deletions from our volume estimates. In addition, future environmental, economic or geologic changes may occur or become known that can result in reserve revisions either upward or downward from prior reserve estimates.

Our business is subject to substantial governmental regulation and permitting requirements as well as on-site environmental liabilities we assumed when we acquired some of our facilities. We may be adversely affected by any future inability to comply with existing or future regulations or requirements or the potentially high cost of complying with such requirements.

Our business is subject to extensive energy, environmental and other laws and regulations of federal, state and local authorities. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to operate our facilities. In the course of complying with these requirements, we may incur significant additional costs. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. In addition, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulation may have a detrimental effect on our business.

In acquiring some of our facilities, we assumed on-site liabilities associated with the environmental condition of those facilities, regardless of when such liabilities arose and whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We strive at all times to be in compliance with all applicable environmental laws and regulations. However, steps to bring our facilities into compliance, if necessary, could be expensive, and thus could adversely affect our results of operation and financial condition. Furthermore, with the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate, we expect our environmental expenditures to be substantial in the future.

Results from class-action litigation and other proceedings regarding reporting of natural gas trading information could adversely affect our business.

In March 2003, we received a request for information from the Commodity Futures Trading Commission, or CFTC, requesting that we produce, among other things, “all documents relating to natural gas and electricity trading” in connection with the CFTC’s industry-wide investigation of trade and trade reporting practices of power and natural gas trading companies. We cooperated fully with the CFTC producing documents and other materials in response to more specific requests relating to the reporting of natural gas trading information to energy industry publications, conducted our own internal investigation into the accuracy of information that former employees of Enserco Energy Inc., our gas marketing subsidiary, voluntarily reported to trade publications, and provided detailed reports of our investigation to the CFTC.

In July 2003, we reached a settlement with the CFTC on this investigation, whereby we agreed to pay a civil monetary penalty of $3.0 million. Subsequent to the settlement of the CFTC investigation, several parties filed putative class-action suits against numerous companies in the natural gas marketing industry, including us. Although we paid a civil monetary penalty in the CFTC action, we cannot guarantee that other legal proceedings, other civil or criminal fines or penalties, or other regulatory action related to this issue will not occur which, in turn, could adversely affect our financial condition or results of operations.

Ongoing changes in the United States utility industry, such as state and federal regulatory changes, a potential increase in the number of our competitors or the imposition of price limitations to address market volatility, could adversely affect our profitability.

The United States electric utility industry is currently experiencing increasing competitive pressures as a result of:

- consumer demands;
- technological advances;
- deregulation;
- greater availability of natural gas-fired power generation, and other factors.

FERC has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses, and deregulation initiatives in a number of states may encourage further disaggregation. As a result, significant additional competitors could become active in the generation, transmission and distribution segments of our industry, which could negatively affect our ability to expand our asset base.

In addition, the independent system operators who oversee many of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. These types of price limitations and other mechanisms may adversely affect the profitability of those generating facilities that sell energy into the wholesale power markets. Given the extreme volatility and lack of meaningful long-term price history in some of these markets and the imposition of price limitations by independent system operators, we may not be able to operate profitably in all wholesale power markets.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” subcaption within Item 8, Note 21, “Commitments and Contingencies”, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2004.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 42, was elected President, Chief Executive Officer and a member of the Board of Directors in January 2004. Prior to that, he was our President and Chief Operating Officer – Retail Business Segment from April 2003 to January 2004 and Vice President-Fuel Resources from January 1997 to April 2003. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 16 years of experience with us. He was previously employed as a petroleum engineer for a large independent oil and gas company. He holds a B.S. in Petroleum Engineering from the University of Wyoming and a M.B.A. from the University of South Dakota.

Thomas M. Ohlmacher, age 53, has been the President and Chief Operating Officer of our Wholesale Energy Group since November 2001. He served as Senior Vice President-Power Supply and Power Marketing from January 2001 to November 2001 and Vice President - Power Supply from 1994 to 2001. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher holds a B.S. in Chemistry from the South Dakota School of Mines and Technology.

Linden R. Evans, age 42, was appointed President and Chief Operating Officer - Retail Business Segment in October 2004. Mr. Evans had been serving as our Vice President and General Manager of our communication subsidiary, since December 2003 and served as our Associate Counsel from May 2001 to December 2003. Prior to joining Black Hills, Mr. Evans was an attorney and member with the Rapid City, South Dakota law firm of Truhe, Beardsley, Jensen, Helmers and VonWald from February 1997 to May 2001, an associate with the Rapid City, South Dakota Marvin D. Truhe Law Office, from April 1995 to February 1997, and an associate with the law firm of Jackson and Kelly, Charleston, West Virginia from December 1992 to April 1995. He was also employed as a mining engineer with several gold mining companies. He holds a J.D. from the Northwestern School of Law, Lewis & Clark College, Portland, Oregon, and a B.S. Degree in Mining Engineering from the University of Missouri.

Mark T. Thies, age 41, has been our Executive Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. From 1990 to 1997, Mr. Thies served in a number of accounting positions with InterCoast Energy Company, an unregulated energy company and a wholly owned subsidiary of MidAmerican Energy Holdings Company. Prior to that time he worked in public accounting. Mr. Thies holds a B.A. in Accounting and a B.A. in Business Administration from Saint Ambrose College and is a Certified Public Accountant.

Steven J. Helmers, age 48, has been our Senior Vice President, General Counsel since January 2004. He served as our Senior Vice President, General Counsel and Corporate Secretary from January 2001 to January 2004. Prior to joining us, Mr. Helmers was an attorney and a shareholder with the Rapid City, South Dakota law firms of Truhe, Beardsley, Jensen, Helmers & VonWald, from 1997 to January 2001, and Lynn, Jackson, Shultz & Lebrun, P.C., from 1983 to 1997. He holds a J.D. from the University of South Dakota School of Law.

Russell L. Cohen, age 44, has been Senior Vice President and Chief Risk Officer since May 2002. Prior to joining Black Hills, Mr. Cohen was General Partner and Chief Financial Officer at Regenesis Group, LLC from December 2000 to April 2002. He was Chief Financial Officer at Worldbridge Broadband Services, Inc. from January 1998 to February 2000, when it was acquired, and left in November 2000. He worked in various derivative products positions at First Boston, Lehman Brothers and Bear Stearns from June 1987 to December 1997. Mr. Cohen holds a B.S. in Economics from Yale University and a M.B.A. from Stanford University.

Maurice T. Klefeker, age 48, was elected Senior Vice President - Strategic Planning and Development in March 2004. Prior to that he served as Senior Vice President of our subsidiary, Black Hills Generation, Inc. from September 2002 to March 2004 and as Vice President of Corporate Development from July 2000 to September 2002. He joined Indeck Capital, Inc. in December 1995 as Asset Manager and later served as Vice President of Business Development until July 2000. Prior to that he served in a variety of technical and engineering positions with Northern Indiana Public Service Company for 14 years. Mr. Klefeker holds a B.S. from Purdue University and a M.B.A. from the University of Notre Dame.

James M. Mattern, age 50, has been the Senior Vice President – Corporate Administration and Compliance since April 2003, Senior Vice President-Corporate Administration from September 1999 to April 2003, and was Vice President-Corporate Administration from January 1994 to September 1999. From 1997 to 1999, he was also Assistant to the CEO. Mr. Mattern has 17 years of experience with us. He holds a B.S. in Social Sciences and an M.S. in Administration from Northern State University.

Roxann R. Basham, age 43, was elected Vice President – Governance and Corporate Secretary in February 2004. Prior to that, she was our Vice President-Controller from March 2000 to January 2004. From December 1997 to March 2000, she was Vice President-Finance and Secretary/Treasurer. From 1993 until December 1997, she served as our Secretary/Treasurer, and has a total of 21 years of experience with us. She holds a B.S. in Business Administration from the University of South Dakota and is a Certified Public Accountant.

Kyle D. White, age 45, has been Vice President – Corporate Affairs since January 30, 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White has 22 years of experience with us. He holds a B.S. and M.S. in Business Administration from the University of South Dakota.

Garner M. Anderson, age 42, has been our Vice President and Treasurer since July 2003. Mr. Anderson has 17 years of experience with us, including positions as Director – Treasury Services and Risk Manager. Mr. Anderson holds a B.S. in Business Administration from the University of South Dakota and a M.B.A. in Finance from Arizona State University, and is a Certified Public Accountant.

Perry S. Krush, age 46, was appointed Vice President – Controller in December 2004. Mr. Krush has over 16 years of experience with us, including positions as Controller – Retail Operations from 2003 to 2004, Director of Accounting for our subsidiary, Black Hills Energy Inc. and Accounting Manager – Fuel Resources from 1997 to 2003. He previously held positions in healthcare administration and public accounting. Mr. Krush holds a B.S. in Business Administration from the University of South Dakota.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on The New York Stock Exchange under the symbol BKH. As of January 31, 2005, we had 5,500 common shareholders of record and approximately 18,000 beneficial owners, representing all 50 states, the District of Columbia and 16 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 2005 meeting, our board of directors raised the quarterly dividend to $0.32 per share, equivalent to an annual dividend of $1.28 per share.

The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities, restrictions under PUHCA and our future business prospects. Our credit facilities contain restrictions on the payment of cash dividends, the most restrictive of which prohibit the payment of cash dividends if our fixed charge coverage ratio, as calculated in our credit agreements, is less than 1.5:1.0, our recourse leverage ratio exceeds 0.65:1.00 or our consolidated net worth does not exceed the sum of $550 million and 50 percent of our aggregate consolidated net income since April 1, 2004. In addition, under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. As part of the order approving our public utility holding company, we agreed that the consolidated company and the utility subsidiaries will maintain at least a 30 percent common equity ratio. Through December 31, 2007, our non-utility subsidiaries are also allowed to pay dividends out of capital and unearned surplus if (i) they have received excess cash as a result of the sale of assets, (ii) they have engaged in a restructuring or reorganization and/or (iii) they are returning capital to an associate company.

Quarterly dividends paid and the high and low common stock prices, as reported in the New York Stock Exchange Composite Transactions, for the last two years were as follows:

Year ended December 31, 2004

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Common stock prices				
High	$32.17	$32.49	$31.60	$31.68
Low	$29.19	$27.83	$26.52	$27.85

Year ended December 31, 2003

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Common stock prices				
High	$28.39	$31.70	$33.54	$33.15
Low	$21.85	$27.00	$29.82	$27.76

UNREGISTERED SECURITIES ISSUED DURING THE FOURTH QUARTER OF 2004

No unregistered securities were issued during the fourth quarter of 2004.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	**(a) Total Number of Shares Purchased**	**(b) Average Price Paid per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**(d) Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs**
October 1, 2004 – October 31, 2004	—	$ —	—	—
November 1, 2004 – November 30, 2004	—	$ —	—	—
December 1, 2004 – December 31, 2004	289 (1)	$ 30.45	—	—
Total	289	$ 30.45	—	—

(1) Shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan.

ITEM 6. SELECTED FINANCIAL DATA

Years ended December 31,	2004	2003	2002	2001	2000
TOTAL ASSETS (in thousands)	$ 2,056,163	$ 2,063,252	$1,999,974	$1,651,765	$1,252,936
PROPERTY, PLANT AND EQUIPMENT (in thousands)					
Total property, plant and equipment	$ 1,971,119	$ 1,882,545	$1,703,220	$1,377,521	$ 911,147
Accumulated depreciation and depletion	525,387	440,274	377,568	297,400	252,816
Capital expenditures	90,974	116,691	303,191	594,142	173,517*
CAPITALIZATION (in thousands)					
Long-term debt, net of current maturities	$ 733,581	$ 868,459	$ 540,958	$ 329,771	$ 213,606
Preferred stock equity	7,167	8,143	5,549	5,549	4,000
Common stock equity	728,598	701,604	529,614	509,615	278,346
Total capitalization	$ 1,469,346	$ 1,578,206	$1,076,121	$ 844,935	$ 495,952
CAPITALIZATION RATIOS					
Long-term debt, net of current maturities	49.9%	55.0%	50.3%	39.0%	43.1%
Preferred stock equity	0.5	0.5	0.5	0.7	0.8
Common stock equity	49.6	44.5	49.2	60.3	56.1
Total	100.0%	100.0%	100.0%	100.0%	100.0%
TOTAL OPERATING REVENUES (in thousands)	$ 1,121,701	$ 1,250,050**	$ 908,477	$ 737,806	$ 741,121
INCOME FROM CONTINUING OPERATIONS BEFORE CHANGE IN ACCOUNTING PRINCIPLE (in thousands)	$ 57,249	$ 56,481	$ 58,138	$ 84,355	$ 52,480
DIVIDENDS PAID ON COMMON STOCK (in thousands)	$ 40,210	$ 37,025	$ 31,116	$ 28,517	$ 23,527
COMMON STOCK DATA					
(in thousands)					
Shares outstanding, average	32,387	30,496	26,803	25,374	22,118
Shares outstanding, average diluted	32,912	31,015	27,167	25,771	22,281
Shares outstanding, end of year	32,478	32,298	26,933	26,652	22,921
(in dollars)					
Basic earnings per average share -					
Continuing operations	$ 1.76	$ 1.84	$ 2.16	$ 3.30	$ 2.37
Discontinued operations	0.02	0.33	0.09	0.15	0.02
Change in accounting principle	—	(0.17)	0.03	—	—
Total	$ 1.78	$ 2.00	$ 2.28	$ 3.45	$ 2.39
Diluted earnings per average share -					
Continuing operations	$ 1.74	$ 1.82	$ 2.14	$ 3.28	$ 2.35
Discontinued operations	0.02	0.32	0.09	0.14	0.02
Change in accounting principle	—	(0.17)	0.03	—	—
Total	$ 1.76	$ 1.97	$ 2.26	$ 3.42	$ 2.37
Dividends paid per share	$ 1.24	$ 1.20	$ 1.16	$ 1.12	$ 1.08
Book value per share, end of year	$ 22.43	$ 21.72	$ 19.66	$ 19.12	$ 12.14
RETURN ON AVERAGE COMMON STOCK EQUITY (year-end)	8.1%	9.9%	11.8%	22.2%	21.3%

*Excludes the non-cash acquisition of Indeck Capital, Inc.
**Includes $114.0 million of contract termination revenue

Certain items related to 2000 to 2003 have been restated from prior year presentations to reflect the classification of Landrica Development Corp. as discontinued operations in 2004.

ITEMS 7 and 7A MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a diversified energy holding company operating principally in the United States with two major business groups – wholesale energy and retail services. We report for our business groups in the following financial segments:

Business Group	Financial Segment
Wholesale energy group	Power generation
	Oil and gas
	Coal mining
	Energy marketing and transportation
Retail services group	Electric utility
	Communications

Our wholesale energy group, which operates through Black Hills Energy, Inc. and its subsidiaries, engages in the production of electric power through ownership of a diversified portfolio of generating plants and the sale of electric power and capacity primarily under long-term "tolling" contracts; the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; and the marketing and transportation of fuel products. Our retail services group currently consists of our electric utility, Black Hills Power, and communications segments. In future filings, we will report the operations of our new combination electric and gas public utility, CLF&P, as its own segment.

Our electric utility, Black Hills Power, Inc., generates, transmits and distributes electricity to an average of approximately 62,000 customers in South Dakota, Wyoming and Montana. Our communications segment provides broadband telecommunication services to approximately 27,000 residential and business customers in Rapid City and the Northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

In May 2004, we sold our subsidiary, Landrica Development Corp., which held some land and coal enhancement facilities that were previously reported in our coal mining segment.

In 2003, we decided to divest of our non-strategic power generation assets located in the Northeastern United States. On September 30, 2003, we sold our seven hydroelectric power plants located in Upstate New York. We currently hold for sale our 40 megawatt Pepperell power plant in Massachusetts.

In 2002, we discontinued operations of our coal marketing business due to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to East Coast markets. The non-strategic assets were sold effective August 1, 2002.

Industry Overview

The energy and telecommunications industries are expected to become increasingly competitive due to a variety of regulatory, economic and technological changes. In addition, the energy sector has become more volatile due to international tensions, changes in investment activity and factors affecting supply and demand of various energy resources.

In recent years, state and federal regulators have been evaluating the results of energy deregulation efforts of the 1990s. These efforts were intended to encourage competition, introduce consumer choice and attract additional investment in energy resources. In many states, electric utilities were required to disaggregate traditional functions of generation, transmission, distribution and marketing of electricity in an effort to open markets to competition. Due to a number of causes, energy consumers have been exposed to significant price increases and deterioration in service in recent years. Because the benefits of a more competitive industry were not always evident, many regulators are now seeking new policy directions to assure greater reliability and end-user value in the future.

A surge in investment in gas-fired power generation facilities occurred in the early 2000s. Some of that investment led to an overabundance of power capacity in certain regions of the country. In some instances, “merchant” or non-contracted plants became financially distressed as market prices for power fell below the cost of production for extended periods during the 2002-2004 time frame. Many of these plants were deemed impaired and asset values were written down. Several companies abandoned their independent power production (IPP) strategy, sold their plants and exited the sector. IPP facilities under contract with utilities have fared better than those subject to volatile market conditions.

Mild weather over vast sections of the U.S. in 2003 and 2004, combined with slower regional economic growth, contributed to a slowdown in electric energy demand nationwide. As a result of excess energy supply, wholesale power prices have been relatively soft for much of the last two years. This situation could turn around abruptly with a resurgence of hotter than normal weather during the summer peaking season and increases in industrial demand. In addition, the availability of hydroelectric power is unpredictable and dependent on precipitation in the northwestern U.S. Power prices in the West can be affected dramatically by changing hydroelectric conditions.

The energy industry experienced a financial crisis beginning in late 2001, stemming from the collapse of Enron Corporation and the near collapse of several other leading energy companies. The aggregate market capitalization of energy companies fell on the scale of hundreds of billions of dollars, reflecting challenging market conditions and investor attitudes. Investors and consumers lost confidence in the financial health and future prospects of many energy providers as a result of numerous events. Accordingly, energy companies have been subject to much greater scrutiny by regulators, credit rating agencies and investors. In response, companies are moving aggressively to improve liquidity and to restructure their balance sheets. They are abandoning unsuccessful business strategies, selling non-core assets, downsizing staffs, issuing new equity, canceling acquisitions, postponing or canceling construction projects, reducing significant levels of capital expenditures, accelerating debt repayment and realigning trading activities around their own generation, mid-stream and transportation assets.

The oil and gas industry has experienced significant price volatility in the past several years, from a lower-price environment in 2002 and 2003 to significantly higher prices for both commodities in 2004 and 2005 to date. In the 2000’s, natural gas has emerged as the national industrial fuel of choice. Most of the recent increase in power generation capacity has been gas-fired, which in turn has exposed the generation companies’ financial performance to greater risk due to fuel price volatility. Recent high product prices have encouraged domestic oil and gas producers to increase production and reserves. In addition, investment in liquefied natural gas port facilities is expected to increase the availability of gas supplies in future years.

The U.S. coal industry has experienced a resurgence in the past two years, with favorable commodity prices creating attractive returns. Coal prices in Wyoming’s Powder River Basin have increased moderately during this period, due to the coal’s lower heat content and high transportation costs. Those factors limit the ability to capture significant additional market share. However, from a regional perspective, Powder River Basin coal can be a very competitive energy resource. Fossil fuel combustion continues to be an international policy issue, with opponents arguing environmental harm, despite the application of advanced emissions technology. Because coal continues to be an economical resource, its long-term prospects as an important component of a national energy mix remain strong.

The telecommunications industry underwent widespread changes brought about by, among other things, the Telecommunications Act of 1996 and the decisions of federal and state regulators to open the monopolistic local telephone and cable television markets to competition. The industry has also experienced the rapid introduction of new broadband technology applications and increased consumer demand for faster, higher-capacity, digital-based and expanded broadband communications services, including broader video choices and high speed data and Internet services. The convergence of these trends allowed many new entrants into the telecommunications market. Due to the rapid expansion of the broadband industry and the effects of technical substitution and obsolescence of equipment, the broadband communications industry’s financial performance has suffered in many U.S. markets.

Business Strategy

We are a customer-focused energy provider. Our business is comprised of fuel assets, electric generation assets and retail utility assets, such as electric and gas distribution systems. To optimize the value of those assets, we utilize our energy marketing and transportation expertise. Our focus on customers, whether retail utility customers or wholesale generation or marketing customers, provides us with opportunities to expand our various businesses. The diversity of our operations avoids reliance on any single business to achieve our strategic objectives. This diversity is expected to provide a measure of stability to our business and financial performance in volatile or cyclical periods. It should help us reduce our total corporate risk and allow us to achieve higher than average market returns over the long term. The strength and stability of our balance sheet is critical in today’s market. Access to capital, sufficient liquidity and quality of earnings are our key drivers.

Our balanced, integrated approach to fuel production, power generation, retail operations and energy marketing is supported by disciplined risk management practices. Additionally, building on the strength of our electric utility, Black Hills Power, we enhanced our Black Hills area operations by providing broadband communications to our customers in South Dakota.

Our long-term strategy is to continue growing our core retail utility, generation and fuel asset businesses, supplemented by our energy marketing and transportation operations. We will do this primarily by focusing on customers. In the retail area, we will focus on acquiring new customers through the acquisition of additional retail utility properties, while maintaining our high customer service and reliability standards. In the power generation area, we will focus on long-term contractual relationships with key wholesale customers, as well as new customers, to allow us to expand existing generation sites, or to construct or acquire new generation facilities. Finally, in the fuel area, we will strive to develop additional markets for our production, including the development of additional power plants at our mine site. The expertise of our energy marketing and transportation businesses will continue to enable us to optimize the value of our asset businesses.

The following are key elements of our business strategy:

- operate our lines of business as retail and wholesale energy components. The retail component consists of electric, natural gas and telecommunications products and services. The wholesale component consists of fuel production, marketing, mid-stream assets and power production facilities;
- preserve Black Hills Power’s low-cost rate structure for our residential, commercial and industrial customers while retaining the flexibility to selectively market excess generating capacity off-system to maximize returns in changing market environments;
- expand retail operations through selective acquisitions of electric utilities consistent with our regional focus and strategic advantages;
- improve our communications business by increasing customer service and value, by increasing revenues and by creating additional operating efficiencies;
- build and maintain strong relationships with wholesale energy customers;
- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;
- sell a large percentage of our capacity and energy production from new independent power projects through mid- and long-term contracts primarily to load serving utilities in order to secure a stable revenue stream and attractive returns;

- grow our power generation segment by developing and acquiring power generating assets in targeted Western markets and, in particular, by expanding generating capacity of our existing sites through a strategy known as “brownfield development;

- exploit our fuel cost advantages and our operating and marketing expertise to produce power at attractive margins;

- increase our reserves of natural gas and crude oil and expand our overall fuel production;

- increase margins from our coal production through an expansion of mine-mouth generation and increased coal sales;

- grow our energy marketing operations primarily through the expansion of producer and end-use origination services, and:

- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure.

Operate our lines of business as retail and wholesale energy components. The retail component consists of electric and telecommunications products and services. The wholesale component consists of fuel production, marketing, mid-stream assets and power production facilities. Through the retail and wholesale groups of our business, operating efficiencies are achieved. In the retail group, the integration of customer service and marketing and promotional efforts streamline operating processes and improve productivity. In the wholesale group, the fuel production, marketing and generation segments integrate balanced, yet diverse strategic operations.

Preserve Black Hills Power’s Low-Cost Rate Structure for our Residential, Commercial and Industrial Customers While Retaining the Flexibility to Selectively Market Excess Generating Capacity Off-System to Maximize Returns in Changing Market Environments. Through a settlement with the SDPUC Black Hills Power has been under a retail rate freeze since 1995. The rate freeze agreement terminated on January 1, 2005. The rate freeze preserved Black Hills Power’s low-cost rate structure at levels below the national average for our retail customers while allowing us to retain the benefits from cost savings and wholesale “off-system” sales. This has provided us with flexibility in allocating Black Hills Power’s generating capacity to maximize returns in changing market environments. We have historically optimized the utilization of Black Hills Power’s power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts. Absent any request for a rate change by us or the SDPUC, rates will remain unchanged from those in place during the rate freeze.

Expand Retail Operations Through Selective Acquisitions of Electric Utilities Consistent with our Regional Focus and Strategic Advantages. For more than 60 years, we have provided strong retail services, based on delivering quality and value to our customers. That tradition and accomplishment is expected to support efforts to expand our retail operations in other markets, most likely in the West and in regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation and system reliability. The January 2005 acquisition of CLF&P is an example of these expansion efforts. Retail operations also can augment other important business development, including transmission and pipelines and storage infrastructure, which could lead to advancing other wholesale operations. Regulated retail operations can contribute substantially to the stability of our long-term cash flows and earnings.

Improve Our Communications Business by Increasing Customer Service and Value, by Increasing Revenues, and by Creating Additional Operating Efficiencies. We are now the leading provider of telephone, cable television and high-speed Internet services in the areas we serve. This accomplishment was initially due to the strength of Black Hills Power's reputation for reliability, customer service and value. More recently, our improvement in operations is due primarily to our service deliverability, reliability and commitment to our broadband customers. We believe this dual strategy – upholding our strong public standing and delivering superior broadband communications products and services – will advance our efforts further in the future. As we continue to seek additional customers and revenue, we will also continue efforts to create operating efficiencies by integrating appropriate business functions with related utility operations, benefiting customers as well as both business segments.

Build and Maintain Strong Relationships With Wholesale Energy Customers. We strive to build strong relationships with utilities, municipalities and other wholesale customers, who we believe will continue to be the primary providers of electricity to retail customers in a deregulated environment. We further believe that these entities will need products, such as capacity, in order to serve their customers reliably. By providing these products under long-term contracts, we are able to meet our customers' energy needs. Through this approach, we also believe we can earn more stable revenues and greater returns over the long term than we could by selling energy into the more volatile spot markets.

Conduct Business with a Diversified Group of Creditworthy or Sufficiently Collateralized Counterparties. Our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diversified group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We accomplish this by establishment of counterparty credit limits, continuous credit monitoring, and regular review of compliance with our credit policy by our executive credit committee that reports to our board of directors.

Sell a Large Percentage of our Capacity and Energy Production From New Independent Power Projects Through Mid- and Long-Term Contracts Primarily to Load Serving Utilities in Order to Secure a Stable Revenue Stream and Attractive Returns. By selling the majority of our energy and capacity under mid- and long-term contracts, we believe that we can satisfy the requirements of our customers while earning more stable revenues and greater returns over the long term than we could by selling our energy into the more volatile spot markets. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Our goal is to sell a substantial majority of our unregulated power generation assets under long-term pre-approved contracts primarily to load serving utilities.

Grow our Power Generation Segment by Developing and Acquiring Power Generating Assets in Targeted Western Markets, and in Particular, by Expanding Generating Capacity of our Existing Sites Through a Strategy Known as "Brownfield Development." We aim to develop power plants in regional markets based on prevailing supply and demand fundamentals in a manner that complements our existing fuel assets and fuel and energy marketing capabilities. This approach seeks to capitalize on market growth while managing our fuel procurement needs. Over the next few years, we intend to grow through a combination of disciplined acquisitions and development of new power generation facilities primarily in the western regions where we believe we have the detailed knowledge of market fundamentals and competitive advantage to achieve attractive returns. We believe the following trends will provide us with growth opportunities in the future:

- Demand for electricity in certain Western regions is expected to grow and new generation capacity will be required over the next several years.
- New electric generation construction will be predominantly gas-fired, which may create further competitive cost advantages for new and existing coal-fired generation assets.
- Transmission construction will significantly lag new generation development, favoring new development located near load centers or existing, unconstrained transmission locations.
- Disaggregation of the electric utility industry from traditionally vertically integrated utilities into separate generation, transmission, distribution and marketing entities may continue in certain regions, thereby creating opportunities for expansions, acquisitions and joint ventures.

We believe that existing sites with opportunities for brownfield expansion generally offer the potential for greater returns than development of new sites through a "greenfield" strategy. Brownfield sites typically offer several competitive advantages over greenfield development, including:

- proximity to existing transmission systems;
- operating cost advantages related to ownership of shared facilities;
- a less costly and time consuming permitting process; and
- potential ability to reduce capital requirements by sharing infrastructure with existing facilities at the same site.

We expanded our capacity with brownfield development at our Valmont and Wyodak sites in 2001, Arapahoe and Las Vegas sites in 2002 and our Wyodak site in 2003. We believe that our Fountain Valley, Wyodak and Las Vegas sites in particular provide further opportunities for significant expansion of our gas- and coal-fired generating capacity over the next several years.

Exploit our Fuel Cost Advantages and our Operating and Marketing Expertise to Produce Power at Attractive Margins. We expect to expand our portfolio of power plants having relatively low marginal costs of producing energy and related products and services. As an increasing number of gas-fired power plants are brought into operation, we intend to utilize a low-cost power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream. Low marginal production costs can result from a variety of factors, including low fuel costs, efficiency in converting fuel into energy, and low per unit operation and maintenance costs. We aggressively manage each of these factors with the goal of achieving very low production costs.

Our primary competitive advantage is our coal mine, which is located in close proximity to our retail service territories. We are exploiting the competitive advantage of this native fuel source by building additional mine-mouth coal-fired generating capacity. This strengthens our position as a low-cost producer since transportation costs often represent the largest component of the delivered cost of coal.

Increase our Reserves of Natural Gas and Crude Oil and Expand our Overall Fuel Production. Our strategy is to expand our natural gas reserves through a combination of acquisitions and drilling programs. We aim to maintain sufficient natural gas production either to directly serve or indirectly hedge the fuel cost exposure of our gas-fired generation plants. Specifically, we plan to:

- substantially increase our natural gas reserves while minimizing exploration risk by focusing on lower-risk exploration and development drilling as well as acquisitions of proven reserves;

- exploit opportunities based on our belief that the long-term demand for natural gas will remain strong by emphasizing natural gas in our acquisition and drilling activities; and

- add natural gas reserves and increase production by focusing primarily on various shallow gas plays in the Rocky Mountain region, where the added production can be integrated with our fuel marketing and/or power generation activities.

Increase Margins From our Coal Production Through an Expansion of Mine-Mouth Generation and Increased Coal Sales. Our strategy is to expand our coal production through the construction of mine-mouth coal-fired generation plants at our Wyodak mine location. Our objective is to maintain coal reserves to serve our mine-mouth coal-fired generation plants directly. Specifically, we plan to:

- increase coal production and sales from our Wyodak mine by continuing to develop additional mine-mouth generating facilities at the site; and
- pursue future sales of coal from the Wyodak mine to regional additional rail-served and truck-served customers.

Grow our Energy Marketing Operations Primarily Through the Expansion of Producer and End-use Origination Services. Our energy marketing activities distinguish themselves from other marketing businesses by focusing on customer services and the physical delivery of energy commodities. With our producer services, we primarily assist natural gas producers in the Rocky Mountain region of the U.S. and Canada with marketing and transporting their commodities to the marketplace. We also provide origination services, where we work with industrial consumers of natural gas, by sourcing and arranging delivery for gas. We expect, because of our regional marketing expertise and proven knowledge of efficiently utilizing storage and transportation infrastructure, that we can increase our marketing volumes as well as provide services to optimize the value of our fuel and generation assets. In the future, we may acquire additional mid-stream assets, such as regional pipelines and storage systems, so that we can facilitate and further augment our marketing services.

Manage the Risks Inherent in Energy Marketing by Maintaining Position Limits That Minimize Price Risk Exposure. Our energy marketing operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we have implemented risk management policies and procedures for each of our marketing companies that establish price risk exposure levels. We formed oversight committees to monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining separate credit facilities for each of our marketing companies.

Prospective Information

We continue to advance our business strategy. We expect long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires continued capital deployment. We believe that we are strategically positioned to take advantage of opportunities to acquire and develop energy assets consistent with our investment criteria and a prudent capital structure.

Our wholesale energy group was our largest contributor to revenue and earnings in 2004 and 2003. We expect that earnings from this group over the next few years will be driven primarily by increased oil and gas production and expansion in power generation. In March 2003 we acquired Mallon Resources Corporation, an energy company engaged in oil and natural gas exploration, development and production primarily in the San Juan Basin of New Mexico. This acquisition more than doubled our reserves, and contributed to a 16 percent increase in production volumes compared to 2003 levels. Although we expect long-term growth in our power generation segment, 2005 power generation earnings are expected to return to a more normalized earnings profile due to the new Las Vegas Cogeneration II contract with Nevada Power Company that began April 1, 2004. We expect lower earnings from our energy marketing and transportation segment due to anticipated decreases in oil marketing and transportation revenue, and lower margins from gas marketing.

Firm electric business at our electric utility, Black Hills Power, remained healthy in 2004. We believe that Black Hills Power will produce modest growth in revenue, and absent unplanned plant outages, it will continue to produce stable earnings for the next several years. We forecast firm energy sales in our retail service territory to increase over the next 10 years at an annual compound growth rate of approximately one percent, with the system demand forecasted to increase at a rate of two percent. These forecasts are derived from studies conducted by us whereby we examined and analyzed our service territory to estimate changes in the needs for electrical energy and demand over a 20-year period. These forecasts are only estimates, and the actual changes in electric sales may be substantially different. Weather deviations can also affect energy sales significantly when compared to forecasts based on normal weather. The portion of the utility's future earnings that will result from wholesale off-system sales will depend on many factors, including native load growth, plant availability, electricity demand and commodity prices.

On January 1, 2005, the South Dakota retail rate freeze under which Black Hills Power has operated since January 1, 2000, expired. The current South Dakota retail electric rates, along with the Wyoming retail electric rates, have been in place since the summer of 1995. These rates, which have remained flat for 10 years, do not include a fuel and/or purchased power adjustment clause but allow Black Hills Power to retain the benefits of off-system wholesale sales and cost reductions. Black Hills Power has no current plans to request approval to change its retail electric rates. Black Hills Power's return is affected by changes in inflation, capital investment, capital markets, and retail and wholesale power sales. Black Hills Power monitors these potential impacts in order to ensure that its return remains adequate for its investment to serve customers.

In January 2005 we acquired Cheyenne Light, Fuel & Power (CLF&P) from Xcel Energy Inc. CLF&P is a utility serving residential, commercial and industrial energy consumers in and around Cheyenne, Wyoming. Currently the utility has approximately 38,000 electric customers and 31,000 gas customers. Its peak load is 163 megawatts and power is provided under an all-requirements contract with PSCo, which extends through 2007. CLF&P's annual natural gas sales and transportation during 2004 were approximately 13.6 million MMbtus, with sales to commercial and residential customers accounting for approximately 4.4 million MMbtus and transportation accounting for approximately 9.2 million MMbtus. We anticipate modest accretion to earnings from the CLF&P acquisition in 2005. A condition of the settlement stipulation approved by the WPSC when it authorized Black Hills Corporation to acquire CLF&P prohibits us from increasing CLF&P's gas or electric base rates prior to January 1, 2006. CLF&P's rates are separated into commodity energy related charges and charges that recover the costs of operating the natural gas and electric distribution systems (base rates). The commodity energy costs are forecasted annually for recovery on a current basis from customers. Also included for recovery/refund are any over or under collections, plus interest, occurring during the prior year. Another condition of the settlement stipulation is that CLF&P is required to file with the WPSC an updated resource plan prior to June 1, 2005. The resource plan will provide information regarding the options being considered for meeting its electricity requirements after December 31, 2007, when the current all-requirements power supply agreement with PSCo expires.

We expect improved results from our broadband communications business in 2005 due to increased revenues and continued improvement in cost containment measures. Integration of certain retail functions will improve customer service and productivity. The recovery of our capital investment and future profitability are dependent primarily on our ability to sustain our customer base and control our expenses, and is subject to the risk of market competition and the risk that technological advances may render our network obsolete. If we determine that we will be unable to recover our investment, we would be required to record a non-cash charge to earnings, in an amount that could be material, in order to write down a portion of our investment. While we do not anticipate being regulated in the local markets, we are unable to predict future markets, future government impositions or future economic and competitive conditions that could affect the profitability of our communications operations.

Part of our long-term growth strategy includes continued capital deployment. We have forecasted capital expenditures of $50 million, $55 million and $96.2 million a year in 2005, 2006 and 2007, respectively, in new projects or acquisitions which are yet to be identified. In addition, our capital requirements forecast includes $38.7 million, $43.9 million and $47.1 million in 2005, 2006 and 2007, respectively, of oil and gas expenditures and $90.0 million in 2005 for the CLF&P acquisition, and $50.0 million and $18.1 million in 2006 and 2007, respectively, for the development of a coal fired plant. Actual deployment of the capital will be dependent on identifying and obtaining or developing projects that meet our investment criteria.

Results of Operations

Consolidated Results

Overview

Revenue and income (loss) from continuing operations provided by each business group as a percentage of our total revenue and net income were as follows:

	2004	2003	2002
Revenue:			
Wholesale energy	81%	83%	79%
Retail services	19	17	21
	100%	100%	100%

	2004	2003	2002
Income (loss) from continuing operations:			
Wholesale energy	79%	81%	66%
Retail services	27	32	39
Corporate	(6)	(13)	(5)
	100%	100%	100%

In May 2004, we sold our subsidiary, Landrica Development Corp., which held some land and coal enhancement facilities that were previously reported in our coal mining segment.

In 2003, we sold our hydroelectric power plants located in upstate New York. The non-strategic assets were sold effective September 30, 2003. We also developed a plan of sale for our 40 MW Pepperell power plant, our last power plant in the Eastern region. These discontinued operations were previously reported in the Power generation segment. During the second quarter of 2002, we adopted a plan to dispose of our coal marketing subsidiary, Black Hills Coal Network, due primarily to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to Midwestern and Eastern coal markets. We sold the non-strategic assets effective August 1, 2002. These discontinued operations were previously reported in the Energy marketing and transportation segment. Results of operations for 2003 and 2002 have been restated to reflect the operations discontinued.

2004 Compared to 2003

Consolidated income from continuing operations for 2004 was $57.2 million, compared to $56.5 million in 2003, or $1.74 per share in 2004, compared to $1.82 per share in 2003. Income from discontinued operations was $0.7 million or $0.02 per share in 2004, compared to $9.9 million or $0.32 per share in 2003. Return on average common equity in 2004 and 2003 was 8.1 percent and 9.9 percent, respectively.

The wholesale energy group’s income from continuing operations decreased $0.4 million in 2004 compared to 2003. Increased income from continuing operations of $3.8 million at our oil and gas operations and $3.5 million from energy marketing and transportation operations were offset by decreased earnings from power generation of $6.8 million and from coal mining of $0.9 million.

The retail services group's income from continuing operations decreased $3.0 million in 2004 compared to 2003. Earnings from continuing operations from the electric utility decreased $4.9 million due to lower margins received, increased maintenance expense and general and administrative costs, offset by lower interest expense. The communication segment's losses decreased $1.9 million in 2004 compared to 2003 due to increased revenues and lower operating costs, offset by increased marketing costs and corporate cost allocations.

Corporate costs for the year ended December 31, 2004 decreased $4.1 million after tax, compared to 2003. The decrease is primarily due to increased allocations to subsidiaries and a $1.0 million pre-tax gain on sale of assets, partially offset by increased costs related to Sarbanes-Oxley compliance, and holding company structuring and higher pension, insurance and interest expense. The Company's subsidiary, Daksoft, Inc., recorded a $1.0 million pre-tax gain on the sale of its campground reservation system. As Daksoft now primarily provides information technology support to the Company, its results of operations are included in Corporate. Prior to 2004, Daksoft's results were included in the Communications segment.

<u>2003 Compared to 2002</u>

Consolidated income from continuing operations for 2003 was $56.5 million, compared to $58.1 million in 2002, or $1.82 per share in 2003, compared to $2.14 per share in 2002. Income from discontinued operations was $9.9 million or $0.32 per share in 2003, compared to $2.4 million or $0.09 per share in 2002. Return on average common equity in 2003 and 2002, was 9.9 percent and 11.8 percent, respectively.

The 2003 earnings per share results were impacted by an approximate 14 percent increase in diluted weighted average shares outstanding primarily related to the dilutive effect of the April 2003 common stock offering in which 4.6 million shares were issued. In addition, results for 2003 included the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately $1.2 million after-tax. These items included:

- a $3.0 million after-tax charge in our energy marketing and transportation segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of $1.9 million in our power generation segment for the impact of a $114.0 million contract termination payment received at the Las Vegas II plant, offset by the related $117.2 million impairment charge taken on that plant;
- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Corporate costs for the year ended December 31, 2003 increased $4.6 million after tax, compared to 2002. The increase was primarily due to a $3.9 million net increase in interest expense, increased healthcare costs and corporate tax expense. Net interest costs increased due to increased borrowings from the $250 million debt issuance in May 2003 and the low returns on short-term investments.

Discussion of results from our operating groups and segments is included in the following pages.

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2003 and 2002 information has been revised to remove information related to operations that were discontinued.

Wholesale Energy Group

	2004	2003 (in thousands)	2002
Revenue:			
Power generation	$ 158,037	$ 284,567*	$ 102,548
Energy marketing and transportation**	662,110	675,586	553,688
Oil and gas	59,534	46,977	26,486
Coal mining	31,967	34,777	31,335
Total revenue	911,648	1,041,907	714,057
Operating expenses**	(817,898)	(948,830)*	(644,951)
Operating income	$ 93,750	$ 93,077	$ 69,106
Income from continuing operations	$ 45,447	$ 45,843	$ 38,176

* Power generation revenue in 2003 includes $114.0 million of contract termination revenue and operating expenses in 2003 includes $117.2 million of impairment of long-lived assets (see Notes 13 and 14 of our Notes to Consoli ated Financial Statements).

** All periods presented reflect a net presentation of revenues at our as marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

2004 Compared to 2003

Income from continuing operations from the Wholesale Energy group for 2004 was $45.4 million, compared to $45.8 million in 2003.

Power generation segment income from continuing operations decreased to $15.6 million in 2004 from $22.4 million in 2003 primarily due to lower revenues at the Las Vegas II and Harbor plants, higher fuel costs at the Las Vegas I plant, and decreased earnings from unconsolidated subsidiaries, offset by lower fuel costs at the Gillette combustion turbine and lower interest expense. Income from continuing operations from our energy marketing and transportation businesses increased $3.5 million due to increased gas marketing volumes and higher margins received and increased oil transportation revenues and oil marketing margins. These increases were partially offset by 2004 unrealized mark-to-market losses of $1.1 million, pre-tax. Oil and gas income from continuing operations increased $3.8 million due to a 16 percent increase in volumes sold and an increase in sales prices for oil and gas, partially offset by increased production expenses. Coal mining income from continuing operations decreased $0.9 million due to a decrease in revenues resulting from scheduled and unscheduled plant outages, and higher depreciation expense, offset by lower general and administrative and direct mining costs.

In addition, 2003 results were $1.2 million lower due to the impact of several non-recurring items as noted below.

2003 Compared to 2002

Income from continuing operations from the Wholesale Energy group for 2003 was $45.8 million, compared to $38.2 million in 2002. Results for 2003 include the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately $1.2 million after-tax. These items include:

- a $3.0 million after-tax charge in our energy marketing and transportation segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of $1.9 million in our power generation segment for the impact of a $114.0 million contract termination payment received at the Las Vegas II plant, offset by the related $117.2 million impairment charge taken on that plant;
- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Power generation segment income from continuing operations increased to $22.4 million in 2003 from $12.5 million in 2002, primarily due to earnings from 314 megawatts of additional capacity that was placed into service early in 2003, partially offset by increased related operating, interest and depreciation costs and fourth quarter losses at the 224 megawatt Las Vegas II plant as prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant’s long-term contract. Income from continuing operations from our energy marketing and transportation businesses decreased to $6.7 million in 2003, compared to $12.7 million in 2002 primarily due to the CFTC settlement and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. Oil and gas income from continuing operations increased to $8.4 million in 2003 compared to $4.8 million in 2002. Results improved due to a 47 percent increase in volumes sold, primarily related to the March 2003 acquisition of Mallon Resources, and higher prices received during 2003, partially offset by higher depletion and operating costs. Coal mining income from continuing operations in 2003 increased to $8.3 million compared to $8.1 million in 2002, due to a 19 percent increase in tons sold, which was partially offset by higher general and administrative and direct mining costs related to the increased production volumes.

Power Generation

Our power generation segment produced the following results:

	2004	2003	2002
		(in thousands)	
Revenue	$ 158,037	$ 284,567*	$ 102,548
Operating income	47,934	58,893	35,362
Income from continuing operations	15,562	22,429	12,523

* Power generation revenue in 2003 includes $114.0 million of contract termination revenue (see Note 13 of our Notes to Consolidated Financial Statements).

	2004	2003	2002
Independent Power Capacity:			
MWs of independent power capacity in service[b]	964	962	950[a]
MWs of independent power capacity under construction	—	—	90

(a) Includes the 224 MW expansion at the Las Vegas II power plant which was placed into service on January 3, 2003.
(b) Capacity in service includes 82 megawatt (Pepperell and hydroelectric) in 2002, which is reported as "Discontinued operations."

2004 Compared to 2003

Power generation segment income from continuing operations decreased to $15.6 million in 2004 from $22.4 million in 2003. Earnings decreased primarily as the result of lower earnings at our Las Vegas II plant. During the first quarter of 2004, prevailing regional power market conditions limited the economic dispatch of this plant subsequent to the termination of the plant's long-term contract in September 2003, and for the remainder of the year, lower contract rates on the new long-term contract. The lower revenue was partially offset by lower depreciation expense at that plant. The decline in segment earnings was also due to higher fuel costs at Las Vegas I; lower revenues at our Harbor plant, offset by lower fuel cost, due to the expiration of a summer peaking agreement; and higher interest expense due to the December 31, 2003 consolidation of our Wygen plant. Equity in earnings of unconsolidated subsidiaries decreased $3.4 million after-tax primarily due to the impact of mark-to-market adjustments at certain power fund investments that use a fair value method of accounting. These items were partially offset by lower fuel costs at our Gillette combustion turbine, a benefit from certain tax adjustments, lower interest expense due to the pay-down of debt, and higher earnings from other revenues. In addition, the segment's 2003 earnings were affected by certain non-recurring items, netting to a benefit of approximately $1.8 million after-tax.

2003 Compared to 2002

Income from continuing operations increased $9.9 million in 2003 compared to 2002 primarily due to increased generation capacity in operation, partially offset by related increases in interest, depreciation, fuel and other operating costs. The increase in income was partially offset by fourth quarter losses at the 224 megawatt Las Vegas II plant as the prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant's long-term contract in September 2003. In addition, 2003 results include several non-recurring items that had a net effect of increasing 2003 results by $1.8 million after-tax. These items include:

- a net $1.9 million after-tax charge for the impact of a $114.0 million contract termination payment at the Las Vegas II plant, offset by the related $117.2 million non-cash impairment charge taken on the plant;
- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity method power fund investments;
- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts.

2003 revenue and operating expense increased 177 percent and 235 percent, respectively, over 2002. The revenue increase is primarily related to $114.0 million contract termination revenue and energy sales and capacity payments on the 224 megawatt gas-fired Las Vegas II plant and the 90 megawatt coal-fired Wygen plant, both of which went into operation early in 2003 and the 50 MW Arapahoe expansion completed in the latter part of 2002. The Las Vegas II plant received capacity and energy payments under a long-term contract only through September 22, 2003, the contract termination date. After the contract termination, the Las Vegas II plant sold power into the market only when it was economic to do so. In December 2003 a new long-term tolling arrangement was entered into with Nevada Power Company, which became effective April 1, 2004. Increased operating expense was primarily due to the $117.2 million asset impairment charge, related to the contract termination and the increased depreciation, fuel, and other operating costs associated with the additional power plants in operation.

Interest expense increased $11.1 million primarily due to interest costs on plant construction projects, completed in the latter part of 2002 and early 2003, being capitalized during construction compared to expensed after the plants became operational.

Energy Marketing and Transportation

Our energy marketing and transportation companies produced the following results:

	2004	2003	2002
		(in thousands)	
Revenue*	$ 662,110	$ 675,586	$ 553,688
Operating income	18,181	12,151	17,816
Income from continuing operations	10,222	6,725	12,739

* All periods presented reflect a net presentation of revenues at our gas marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

The following is a summary of energy marketing average daily volumes:

	2004	2003	2002
Natural gas physical sales – MMbtus	1,226,600	897,850	683,500
Natural gas financial sales - MMbtus	514,500	344,050	404,700
Crude oil – barrels	44,900	58,700	57,200

2004 Compared to 2003

Income from continuing operations increased $3.5 million due to a 40 percent increase in natural gas volumes marketed and a 12 percent increase in natural gas margins received. Earnings were also impacted by increased earnings from oil transportation and marketing due to increased transportation revenues and higher marketing margins. Decreased oil marketing revenues were more than offset by lower cost of sales resulting in the higher marketing margins. These increases were partially offset by unrealized losses recognized through mark-to-market accounting treatment of $1.1 million in 2004 compared to gains of $2.6 million in 2003 resulting in a year-over-year decrease of $3.7 million pre-tax. In addition, 2003 earnings were impacted by the $3.0 million CFTC settlement.

2003 Compared to 2002

Income from continuing operations decreased $6.0 million due to a $3.0 million after-tax charge for the settlement with the CFTC and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. In addition, as a result of changing commodity prices, results were impacted by unrealized gains recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market gains were $2.6 million in 2003 compared to losses of $0.9 million in 2002, resulting in a year-over-year pre-tax increase of $3.5 million.

Revenues increased 22 percent from 2002 due to a 3 percent increase in average daily volumes of crude oil marketed at average prices 20 percent higher than 2002. These higher revenues were substantially offset by increased operating expenses for the purchases of crude oil used in marketing.

Oil and Gas

Oil and gas operating results were as follows:

	2004	2003	2002
		(in thousands)	
Revenue	$ 59,534	$ 46,977	$ 26,486
Operating income	19,181	13,258	6,471
Income from continuing operations	12,200	8,400	4,783

The following is a summary of oil and natural gas production:

	2004	2003	2002
Barrels of oil sold	432,400	415,800	452,500
Mcf of natural gas sold	10,000,100	8,348,400	4,682,600
Mcf equivalent sales	12,594,600	10,843,400	7,397,800

The following is a summary of our proved oil and gas reserves and 10 percent estimated present value of future net revenues discounted using a 10 percent rate, at December 31:

	2004	2003	2002
Barrels of oil (in thousands)	5,239	5,389	4,880
MMcf of natural gas	141,983	124,062	28,513
Total in MMcf equivalents	173,417	156,399	57,793
Present value of estimated future net revenues before tax (in thousands)	$ 394,446	$ 265,341	$ 94,165

These reserves are based on reports prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. Reserves were determined using constant product prices at the end of the respective years. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Reserves at December 31, 2003 include the March 10, 2003 acquisition of Mallon Resources Corporation. Reserves reflect year end pricing of:

	2004		2003		2002	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 43.45	$ 6.15	$ 32.52	$ 6.19	$ 31.20	$ 4.60
Year-end prices (average well-head)	$ 41.19	$ 5.55	$ 30.56	$ 4.63	$ 29.24	$ 3.41

2004 Compared to 2003

Income from continuing operations increased $3.8 million due to a 16 percent increase in volumes sold, primarily related to a full year of production from properties acquired in the March 2003 Mallon Resources acquisition. Average gas and oil prices received in 2004, including the effects of hedging, were $4.40/Mcf and $26.24/bbl, respectively, compared to $3.81/Mcf and $25.09/bbl in 2003. Total operating expenses increased 20 percent primarily related to increased depletion, production taxes and operating costs associated with the increased production as well as higher corporate cost allocations. In addition, 2004 lease operating expenses per Mcfe sold (LOE/MCFE) increased 2 percent from $0.95 per Mcfe to $0.97 per Mcfe; and depletion per Mcfe sold increased 11 percent from $0.83 per Mcfe to $0.92 per Mcfe.

2003 Compared to 2002

Income from continuing operations increased $3.6 million due to a 47 percent increase in volumes sold, primarily related to production from properties acquired in the March 2003 Mallon Resources acquisition. Average gas and oil prices received in 2003, including the effects of hedging, were $3.81/Mcf and $25.09/bbl, respectively, compared to $2.45/Mcf and $23.01/bbl in 2002. Total operating expenses increased 69 percent primarily related to the additional operations acquired in the Mallon transaction. In addition, 2003 lease operating expenses per Mcfe sold (LOE/MCFE) increased 38 percent from $0.69 per Mcfe to $0.95 per Mcfe; and 2003 depletion per Mcfe sold decreased 15 percent from $0.98 per Mcfe to $0.83 per Mcfe.

Additional information on our Oil and Gas operations can be found in Note 26 to our Notes to Consolidated Financial Statements.

Coal Mining

Coal mining results were as follows:

	2004	2003 (in thousands)	2002
Revenue	$ 31,967	$ 34,777	$ 31,335
Operating income	8,454	8,775	9,457
Income from continuing operations	7,463	8,289	8,131

The following is a summary of coal sales quantities:

	2004	2003	2002
Tons of coal sold	4,780,100	4,812,300	4,052,400
Coal reserves (millions of tons)	294	263	273

2004 Compared to 2003

Income from continuing operations decreased 10 percent as a result of lower revenues due primarily to scheduled and unscheduled plant outages and an increase in depreciation expense partially offset by lower general and administrative and direct mining costs. Decreased coal tons sold were primarily the result of scheduled and unscheduled plant maintenance outages at the Wyodak plant partially offset by increased sales to the Wygen plant.

In September 2004, the Company reached a tax settlement with the Wyoming Department of Revenue, which resulted in an adjustment to coal billings for the period of fourth quarter 2001 through the year 2003. In 2004, the Company recorded a $1.7 million reduction in revenues and a corresponding reduction in mineral taxes as a result of the settlement. The Company also recorded an additional $0.4 million decrease to mineral taxes and $0.5 million decrease to interest expense in 2004 related to settlement accruals.

2003 Compared to 2002

Income from continuing operations increased $0.2 million due to a 19 percent increase in tons sold, partially offset by a 6 percent decrease in average sales price per ton and an increase in general and administrative and direct mining costs related to the increased production. Increased coal tons sold were the result of sales to our 90 megawatt Wygen power plant that became operational in February 2003 and additional sales through our train load-out facility.

Retail Services Group

Income from continuing operations for the retail services group decreased $3.0 million. Earnings from the electric utility segment decreased $4.9 million, while losses from the communications segment decreased $1.9 million.

Electric Utility

	2004	2003 (in thousands)	2002
Revenue	$ 173,745	$ 171,019	$ 162,186
Operating expenses	129,936	119,920	104,026
Operating income	$ 43,809	$ 51,099	$ 58,160
Income from continuing operations and net income	$ 19,209	$ 24,089	$ 30,217

The following table provides certain electric utility operating statistics:

	2004	2003	2002
Firm electric sales – MWh	1,959,969	1,994,819	1,966,060
Wholesale off-system – MWh	1,090,827	930,706	979,677

We currently have a winter peak load of 344 megawatts established in December 1998 and a summer peak load of 392 megawatts established in August 2001. We own 435 megawatts of electric utility generating capacity and purchase an additional 50 megawatts under a long-term agreement.

2004 Compared to 2003

Electric revenue increased 2 percent in 2004 compared to 2003, primarily due to a 16 percent increase in wholesale off-system sales offset by decreased transmission revenues due to lower approved rates and higher load share of our Open Access Transmission Tariff revenues.

Firm kilowatt-hour sales decreased 2 percent. Residential and commercial sales decreases of 3 percent and 2 percent, respectively, in 2004 accounted for a $1.7 million decrease in revenue. These decreases were partially offset by a 1 percent increase in industrial sales. The 16 percent increase in wholesale off-system sales accounted for a $5.9 million increase in revenues.

Revenue per kilowatt-hour sold was 5.5 cents in 2004 compared to 5.6 cents in 2003. The number of customers in the service area increased to 62,259 in 2004 from 61,148 in 2003. Degree days, which is a measure of weather trends, were 11 percent below last year and 9 percent below normal.

Electric utility operating expenses increased $10.0 million due to a $5.9 million increase in fuel and purchased power cost, a $4.5 million increase in certain operations and maintenance costs, including scheduled and unscheduled maintenance costs, increased group insurance and corporate allocations and increased costs associated with the increase in wholesale off-system sales, partially offset by decreased interest expense of $0.9 million, primarily due to retirement of debt.

The increase in fuel and purchased power cost was due to an $11.8 million increase in purchased power costs, offset by a $5.9 million decrease in fuel costs, as prevailing gas prices made it more economical for us to purchase power for our peaking needs and increased off-system sales, rather than generate energy utilizing our gas turbines.

2003 Compared to 2002

Electric revenue increased 5 percent in 2003 compared to 2002, primarily due to an 18 percent increase in wholesale off-system sales at an average price that was 24 percent higher than the average price in 2002.

Firm kilowatt-hour sales increased 1 percent. Residential and commercial sales increases of 2 percent and 3 percent, respectively, in 2003 accounted for a $2.1 million increase in revenue. The 18 percent increase in wholesale off-system sales accounted for a $5.8 million increase in revenues. These increases were offset by a 4 percent decrease in industrial sales, primarily due to the closing of Homestake Mine, which had been one of our largest customers.

Revenue per kilowatt-hour sold was 5.6 cents in 2003 compared to 5.3 cents in 2002. The number of customers in the service area increased to 61,148 in 2003 from 59,948 in 2002.

Electric utility operating expenses increased $15.9 million due to a $10.1 million increase in fuel and purchased power cost, a $3.7 million increase in certain operations and maintenance costs, including pension expense, a $1.5 million increase in depreciation expense and a $2.5 million increase in interest expense due to the full year impact of $75 million of first mortgage bonds issued in August 2002.

The increase in fuel cost was due to a 77 percent increase in average gas prices for combustion turbine generation facilities and a 19 percent increase in average megawatt-hour purchased power costs.

Communications

	2004	2003	2002
		(in thousands)	
Revenue	$ 39,586	$ 39,763	$ 32,677
Operating expenses	41,920	45,004	40,124
Operating loss	$ (2,334)	$ (5,241)	$ (7,447)
Loss from continuing operations and net loss	$ (3,941)	$ (5,880)	$ (7,260)

	2004	2003	2002
Residential customers	23,663	23,878	21,700
Revenue generating units*	56,835	53,568	48,285
Business customers	3,317	3,012**	3,061
Hybrid fiber coaxial cable miles	845	840	818

* Total Revenue generating units (RGU) equal the total number of services to which residential customers subscribe. Telephone, cable TV and Internet access each represent an RGU.

** In 2003, reported business customers were adjusted for the consolidation of multiple-location business customers, business orders and temporary business access lines.

In September 1998, we formed our broadband communications business to provide facilities-based communications services for Rapid City and the Northern Black Hills of South Dakota. As of December 31, 2004, we had invested approximately $165 million in state-of-the-art technology that offers local and long distance telephone service, expanded cable television service, Internet access, and high-speed data and video services. We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers.

2004 Compared to 2003

Loss from continuing operations was $3.9 million in 2004 compared to $5.9 million in 2003. Results for 2003 and 2002 include our information technology support subsidiary, Daksoft, Inc. Beginning in the first quarter of 2004, Daksoft's focus became corporate information technology support and therefore its results are now included as "corporate" costs. Daksoft's results had an insignificant impact on 2003 net earnings. The improved performance, excluding Daksoft's 2003 results, was due to increased revenues from a larger commercial customer base and increased sales of internet services to residential customers and decreased cost of goods sold and operating costs. These were partially offset by $0.6 million in sales incentive costs related to higher marketing campaign costs in response to competitive pressures and an increase in allocated corporate costs.

2003 Compared to 2002

Loss from continuing operations was $5.9 million in 2003 compared to $7.3 million in 2002. The improved performance was due to increased revenues from a larger customer base and an additional $2.4 million in revenues from a successful directory publication and distribution, partially offset by $0.5 million in sales incentive costs related to a current marketing campaign in response to competitive pressures. Revenue increases were also partially offset by a $2.0 million increase in cost of sales and a $1.8 million increase in depreciation expense. In addition, 2002 results included a $0.6 million after-tax benefit from the collection of previously reserved amounts.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We believe the following accounting policies are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting policies and related disclosures with our Audit Committee.

Impairment of Long-lived Assets

We evaluate for impairment, the carrying values of our long-lived assets, including goodwill and other intangibles, whenever indicators of impairment exist and at least annually for goodwill as required by SFAS 142.

For long-lived assets with finite lives, this evaluation is based upon our projections of anticipated future cash flows (undiscounted and without interest charges) from the assets being evaluated. If the sum of the anticipated future cash flows over the expected useful life of the assets is less than the assets' carrying value, then a permanent non-cash write-down equal to the difference between the assets' carrying value and the assets' fair value is required to be charged to earnings. In estimating future cash flows, we generally use a probability weighted average expected cash flow method with assumptions based on those used for internal budgets. Although we believe our estimates of future cash flows are reasonable, different assumptions regarding such cash flows could materially affect our evaluations.

In 2004, an impairment charge of approximately $0.7 million after-tax was recorded to reduce the carrying value of the Pepperell plant to its estimated fair value, less cost to sell and is included in "Income from discontinued operations, net of taxes" on the 2004 Consolidated Statement of Income.

Our Communications business segment began providing broadband communications services in November 1999 and since that time has not achieved profitability. In each of the last five years, we have evaluated the assets of our Communications business segment for impairment, and in each year we determined, based on our assumptions, that the sum of the anticipated future cash flows (undiscounted and without interest charges) exceeded the carrying value and, therefore, we did not recognize an impairment. The carrying value of the assets tested for impairment was approximately $110 million at December 31, 2004. Any increases in the anticipated future cash flows would have no impact on the carrying value of these assets. If our current estimates of future cash flows from the operation of these assets had been 10 percent lower, we still would not have been required to record an impairment charge.

As a result of the 2003 transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, for capacity and energy at the Company's Las Vegas Cogeneration II power plant, we assessed the recoverability of the carrying value of the facility. The carrying value of the assets tested for impairment was $237.2 million. This assessment resulted in a pre-tax impairment charge of $117.2 million to write-down the related property, plant and equipment by $83.1 million, net of accumulated depreciation of $5.1 million, and intangible assets by $34.1 million, net of accumulated amortization of $1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows.

In measuring the fair value of the Las Vegas II power plant and the resulting impairment charge, we considered a number of possible cash flow models associated with the various probable operating assumptions and pricing for the capacity and energy of the facility. We then made our best determination of the relative likelihood of the various models in computing a weighted average expected cash flow for the facility. Inclusion of other possible cash flow scenarios and/or different weighting of those that were included could have led to different conclusions about the fair value of the plant. Further, the weighted average cash flow method is sensitive to the discount rate assumption. If we had used a discount rate that was 1 percent higher, the resulting impairment charge would have been approximately $7.0 million higher. If the discount rate would have been 1 percent lower, the impairment charge would have been approximately $8.0 million lower.

For long-lived assets with indefinite lives, SFAS 142 requires an annual impairment test. Upon adopting SFAS 142 on January 1, 2002, we completed a transition impairment test in the first quarter of 2002. As a result of this impairment test, we recognized a $0.8 million after-tax impairment charge related to the goodwill at our discontinued coal marketing operations. This impairment charge is reported as part of “Income from discontinued operations, net of taxes” on the 2002 Consolidated Statement of Income. This impairment charge was offset by income of $0.9 million, after-tax, from the write-off of negative goodwill at our power generation segment, as required by SFAS 142. This amount is reported as “Change in accounting principles, net of taxes” on the 2002 Consolidated Statement of Income. We completed our 2004 annual goodwill impairment test in the fourth quarter. This test did not result in an additional goodwill impairment.

Full Cost Method of Accounting for Oil and Gas Activities

We account for our oil and gas activities under the full cost method whereby all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a “ceilings test” that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon actual oil and gas prices at the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Although our net capitalized costs were less than the full cost ceiling at December 31, 2004, we cannot assure you that a write-down in the future will not occur depending on oil and gas prices at that point in time. In addition, we rely on an independent consulting and engineering firm to verify the estimates we use to determine the amount of our proved reserves and those estimates are based on a number of assumptions about variables. We cannot assure you that these assumptions will not differ from actual results.

Risk Management Activities

We enter into derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. In addition to the information provided below, see Note 2 of our Notes to Consolidated Financial Statements.

Non-trading (Hedging)

Our typical non-trading (hedging) transactions relate to contracts we enter into at our oil and gas exploration and production subsidiary to fix the price received for anticipated future production; and interest rate swaps we enter into to convert a portion of our variable rate debt to a fixed rate. For these and similar transactions, we utilize hedge accounting treatment under SFAS 133 “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133). As cash flow hedges, these derivative instruments are recorded at fair value on the Consolidated Balance Sheets and the effective portion of the gain or loss is reported in other comprehensive income and the ineffective portion in earnings.

Energy Trading and Marketing

Our natural gas marketing operations currently fall under the purview of Emerging Issues Task Force Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3), SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. The current fair values of natural gas trading contracts that qualify as derivatives in accordance with SFAS 133 are recorded on the Consolidated Balance Sheets and any period-to-period change in the current fair value of such contracts is recognized in the Consolidated Statements of Income. We have presented the net unrealized and realized gains and losses, whether or not settled financially or physically, from the activities of our natural gas marketing business, in Operating revenues on the Consolidated Statements of Income.

For our crude oil marketing operations, substantially all crude oil contracts historically met the definition of "energy trading activities" under EITF 98-10. Accordingly, all contracts at these operations that originated on or before October 25, 2002 have been accounted for at fair value. With the adoption of EITF 02-3, the contracts at our crude oil marketing operations are no longer recorded at fair value since they do not meet the definition of derivatives or have been exempted from mark-to-market accounting as normal purchase and normal sales contracts. These contracts are accounted for under the accrual method of accounting.

Valuation

Fair values of derivative instruments and energy trading contracts are based on listed market prices, where possible. If market prices are not available, fair value is determined based on other relevant factors and pricing models that consider current market and contractual prices for the underlying financial instruments or commodities, as well as time value and yield curve or volatility factors underlying the positions.

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded, and the use of different pricing models or assumptions could produce different financial results. Changes in the commodity markets will impact our estimates of fair value in the future. To the extent financial contracts have extended maturity dates, our estimates of fair value may involve greater subjectivity due to the lack of transparent market data available upon which to base modeling assumptions.

Counterparty Credit Risk

We perform ongoing credit evaluations of our customers and adjust credit and tenor limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current financial information. We continuously monitor collections and payments from our customers and maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and established provisions, we cannot be assured that our credit losses will be consistent with our estimates.

Pension and Other Postretirement Benefits

The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions used by actuaries in calculating the amounts. Those assumptions, as further described in Note 20 of our Notes to the Consolidated Financial Statements, include, among others, the discount rate, the expected long-term rate of return on plan assets and the rate of increase in compensation levels and healthcare costs. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

Defined Benefit Pension Plan

We account for our defined benefit pension plan in accordance with SFAS 87, "Employers' Accounting for Pensions" (SFAS 87). In accordance with SFAS 87, changes in pension obligations associated with fluctuations in long-term actuarial assumptions may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of the plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. For the years ended December 31, 2004, 2003 and 2002, we recorded non-cash expense related to our pension plans of approximately $2.6 million, $3.2 million, and $0.2 million, respectively.

Our pension plan assets are held in trust and primarily consist of equity securities. Fluctuations in actual equity market returns result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting an assumed rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan and weight the returns by applying the assumed rate of return for each asset class to the target allocation for each asset class in the portfolio. The value of our qualified pension plan assets increased $4.0 million to $52.8 million for the plan fiscal year ended September 30, 2004. Plan assets earned $6.3 million in 2004. Plan assets increased $16.4 million to $48.8 million as of September 30, 2003, due to our $10.5 million contribution to the plan and improved performance of the stock market during 2003. Plan assets earned $8.1 million in 2003. In the recently completed actuarial valuation, for determining our 2005 pension expense, we decreased the assumed rate of return on plan assets from 9.5 percent to 9.0 percent. This change is expected to increase pension costs in 2005 and beyond by approximately $0.3 million per year. The expected long-term rate of return on plan assets was 9.5 percent, 10 percent and 10.5 percent for the 2004, 2003 and 2002 plan years, respectively.

The 9.5 percent assumed rate of return for the 2004 plan year was determined based on the following estimated long-term investment allocations and asset class returns:

Asset Class	Estimated Allocation	Estimated Return	Weighted Average Return
Equity	90%	10.0%	9.0%
Fixed Income	5	6.0	0.3
Cash	5	4.0	0.2
	100%		9.5%

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 individual asset classes. 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 10.0 percent and 10.5 percent for the 2004 and 2003 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed 20-, 30-, 40-, and 50-year annual returns for the S&P 500 Index, which were, at December 31, 2004, 13.2 percent, 13.7 percent, 10.4 percent and 10.9 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 intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. 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.

The discount rate we utilize for determining future benefit obligations is based on high grade bond rates. The discount rate was decreased to 6.0 percent for the 2004 pension cost determination from 6.75 percent in 2003. A 0.5 percent decrease in the discount rate would cause annual pension expense to increase by approximately $0.5 million.

Based on our recently completed plan forecasts, we estimate that we will not be required to make cash contributions to the pension plan during the next five years.

Actual pension expense and contributions required will depend on future investment performance, changes in future discount rates, the level of contributions we make and various other factors related to the populations participating in the pension plan. We will continue to evaluate all of the actuarial assumptions, generally on an annual basis, including the expected long-term rate of return on assets and discount rate, and will adjust the assumptions as necessary.

Non-qualified Pension Plans

We have various supplemental retirement plans for our outside directors and key executives. The plans are nonqualified defined benefit plans accounted for in accordance with SFAS 87. Expenses recognized under the plans were $2.3 million in 2004, $1.7 million in 2003, and $0.8 million in 2002. The plans are unfunded. The actuarial assumptions used for our non-qualified pension plans are the same as those used for our qualified plan.

Other Postretirement Benefits

We account for our other postretirement benefit costs in accordance with SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions” (SFAS 106). We do not pre-fund our other postretirement benefit plan. Our reported costs of providing other postretirement benefits are dependent upon numerous factors, including healthcare cost trends, and result from actual plan experience and assumptions of future experience. As a result of these factors, significant portions of other postretirement benefit costs recorded in any period do not reflect the actual benefits provided to plan participants. For the years ended December 31, 2004, 2003 and 2002, we recorded other postretirement benefit expense of approximately $1.5 million, $1.2 million and $1.0 million, respectively, in accordance with SFAS 106. Actual payments of benefits to retirees during these periods were approximately $0.6 million per year.

The following table reflects the sensitivities associated with a change in the assumed healthcare cost trend rate.

Change in Assumption	Impact on December 31, 2004 Accumulated Postretirement Benefit Obligation	Impact on 2004 Service and Interest Cost
	(in thousands)	
Increase 1%	$ 2,190	$ 291
Decrease 1%	$ (1,714)	$ (223)

In selecting assumed healthcare cost trend rates, we consider recent plan experience and various short and long-term cost forecasts for the healthcare industry. Based on these considerations, we changed the healthcare cost trend rate used by the actuaries to determine our other postretirement benefit expense, for 2004 and beyond, to 12 percent in 2004 decreasing gradually to 5 percent in 2011. The healthcare cost trend rate assumption was changed from 11 percent decreasing gradually to 5 percent. These changes increased the future other postretirement benefit expense included on our income statement by approximately $0.2 million. Our discount rate assumption for postretirement benefits is consistent with that used in the calculation of pension benefits. See the Defined Benefit Pension Plan discussion above regarding our discount rate assumptions.

Valuation of Deferred Tax Assets

We use the liability method of accounting for income taxes. Under this 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. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we were unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made.

Liquidity and Capital Resources

Overview

Information about our financial position as of December 31, 2004 and 2003, is presented in the following table:

Financial Position Summary	2004	2003	% Change
	(in thousands)		
Cash and cash equivalents	$ 64,506	$ 172,759	(63)%
Short-term debt	40,166	17,659	127%
Long-term debt	733,581	868,459	(16)%
Stockholders' equity	735,765	709,747	4%
Ratios			
Long-term debt ratio	49.9%	55.0%	(9)%
Total debt ratio	51.3%	55.5%	(8)%

Our dividend payout ratio at December 31, 2004 was approximately 70 percent which is higher than levels over the past 5 years. Based on current expectations for 2005, we expect payout ratios for 2005 to be in the range of 64 percent to 69 percent.

In 2005, we expect our beginning cash balance, cash provided from operations, and available credit facilities to be sufficient to meet our normal operating commitments, to pay dividends and to fund a portion of planned capital expenditures. We would expect to fund a significant portion of any additional investment in power generating facilities with long-term debt.

Cash Flow Activities

2004

In 2004, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily through a combination of cash on hand and operating cash flow.

Cash flows from operations decreased $34.0 million from the prior year amount, primarily due to the net effect of the 2003 Las Vegas II power plant sales contract termination and related impairment charge partially offset by a $32.9 million year-over-year increase in deferred taxes, a $47.8 million increase in the change in operating assets and liabilities and a $7.0 million increase in depreciation and depletion expense. In 2004, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with mining development and oil exploration costs and accelerated depreciation and other plant related costs.

We had cash outflows from investing activities of $92.9 million, primarily for property, plant and equipment additions in the normal course of business. We had cash outflows from financing activities of $152.1 million, primarily due to the repayment of $155.0 million of long-term debt, partially offset by a $24.0 million increase in short-term borrowings and the refinancing of $18.7 million of pollution control revenue bonds. A detailed description of the significant investing and financing activities follows:

- On January 30, 2004, we prepaid $45 million of the long-term debt outstanding on the project-level debt at our Fountain Valley facility.
- On May 10, 2004, we repurchased $25 million of our 6.5 percent senior unsecured notes due 2013.
- On May 13, 2004, we closed on a $125 million 364-day credit facility, which replaced the $200 million facility which was due to expire in August 2004. We also amended our $225 million multi-year facility that expires in August 2006 to conform its compliance calculation to the same calculation as in the new $125 million facility. We had borrowings of $24.0 million under these facilities at December 31, 2004. After inclusion of applicable letters of credit, the remaining borrowing capacity under the facilities was $281.4 million at December 31, 2004.
- On August 31, 2004, we effected a call on Black Hills Power’s $5.9 million, 6.7 percent Pollution Control Revenue Bonds issued through Lawrence County, South Dakota. The bonds had a maturity date of 2010.
- October 1, 2004, we effected a call and refinanced Black Hills Power’s $18.7 million of Pollution Control Revenue Bonds. $6.5 million of the bonds had a maturity date of 2014 and $12.2 million of the bonds had a maturity date of 2024.
- On October 21, 2004, we effected a call on Black Hills Power’s entire $45 million Series AB 8.3 percent First Mortgage bonds. The bonds had a maturity date of 2024.

<u>2003</u>

In 2003, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily through a combination of cash on hand and operating cash flow.

Cash flows from operations decreased $42.3 million over the prior year amount, primarily due to a $37.3 million decrease in the year over year change in deferred taxes and a $140.4 million decrease in the change in operating assets and liabilities, partially offset by the net effect of the Las Vegas II power plant sales contract termination and related impairment charge and a $16.9 million increase in depreciation and depletion expense. In 2002, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with accelerated depreciation and expenses related to our large capital investment in power generation assets in 2002 and 2001. In 2003, the change in our deferred tax liability returned to a more normal level. During the third quarter of 2003, we received $114 million from Allegheny Energy Supply Company, LLC for the termination of a fifteen-year contract for capacity and energy at our Las Vegas II power plant.

We had cash inflows from investing activities of $77.8 million, which includes approximately $186 million from the sale of seven hydroelectric power plants located in upstate New York, partially offset by $104.5 million for property, plant and equipment additions and the acquisition of assets. We had cash outflows from financing activities of $150.7 million, primarily due to the repayment of $139.3 million debt, offset by the net proceeds of $118.0 million from a public offering of 4.6 million shares of common stock and the sale of $250 million ten-year notes. A detailed description of the significant investing and financing activities follows:

- On April 30, 2003, we completed a public offering of 4.6 million shares of common stock at $27 per share. Net proceeds were approximately $118 million after commissions and expenses. The proceeds were used to pay off a $50 million credit facility due in May 2003 and to repay $68 million under our 364-day revolving credit facility which expired on August 26, 2003.

- On May 21, 2003, we issued $250 million 6.5 percent ten-year, senior unsecured notes. Net proceeds from the note offering were approximately $247 million after the discount, commissions and expenses. The proceeds were used to repay our $35 million term loan due September 30, 2004, all of our short-term borrowings under our $195 million, 364-day revolving credit facility and all of our outstanding notes payable under our three-year revolving credit facility which expires on August 24, 2004.

- In August 2003, we closed on a $225 million multi-year, unsecured revolving credit facility that expires on August 20, 2006. The credit facility replaced the $195 million facility that expired in August 2003 and supplements the $200 million facility that expires in August 2004.

- In September 2003, we paid off all of the project-level debt and related interest rate swaps totaling $91.1 million associated with the seven hydroelectric power plants that were sold.

Dividends

Dividends paid on our common stock totaled $1.24 per share in 2004. This reflected increases approved by our board of directors from $1.20 per share in 2003 and $1.16 per share in 2002. All dividends were paid out of current earnings. Our three-year annualized dividend growth rate was 3.5 percent. In January 2005, our board of directors increased the quarterly dividend 3.2 percent to $0.32 cents per share. If this dividend is maintained during 2005, it will be equivalent to $1.28 per share, an annual increase of $0.04 cents per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under PUHCA, restrictions under our credit facilities and our future business prospects.

Short-Term Liquidity

Our principal sources of short-term liquidity include our cash on hand, our revolving bank facilities and cash provided by operations. As of December 31, 2004 we had approximately $64.5 million of cash unrestricted for operations and $350 million of credit through revolving bank facilities. Approximately $17.7 million of the cash balance at December 31, 2004 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company. The bank facilities consist of a $225 million facility due August 20, 2006 and a $125 million facility due May 12, 2005. These bank facilities can be used to fund our working capital needs, for general corporate purposes, and to provide liquidity for a commercial paper program if implemented. At December 31, 2004, we had $24 million of bank borrowings outstanding under these facilities. After inclusion of applicable letters of credit, the remaining borrowing capacity under the bank facilities was $281.4 million at December 31, 2004.

The above bank facilities include financial covenants the most restrictive of which are as follows:

- a consolidated net worth in an amount of not less than the sum of $550 million and 50 percent of our aggregate consolidated net income beginning April 1, 2004;
- a recourse leverage ratio not to exceed 0.65 to 1.00;
- and a fixed charge coverage ratio of not less than 1.5 to 1.0.

If these covenants are violated and we are unable to negotiate a waiver or amendment thereof, the lender would have the right to declare an event of default, terminate the remaining commitment and accelerate all principal and interest outstanding. As of December 31, 2004, we were in compliance with the above covenants.

Our liquidity position remained ample in 2004, albeit at lower levels than at the end of the prior year. Our reduction in liquidity is reflected in our lower levels of cash on hand and in the reduced level of capacity on our corporate revolving credit line.

Our cash levels at the end of 2004 were $108.3 million lower than at the end of 2003, due to optional reductions of debt and due to purchases of natural gas inventory.

In 2004, we used a portion of our cash to reduce our aggregate short-term and long-term borrowings by $112.4 million. In January, 2004 we prepaid $45 million of long-term debt at our Fountain Valley facility; in May, 2004 we purchased and retired $25 million of the 6.5 percent senior unsecured notes due in 2013; in August, 2004 we called $5.9 million of the 6.7 percent Pollution Control Revenue Bonds due in 2010; in October, 2004 we called $45 million of the Series AB 8.3 percent First Mortgage Bonds and also called and refinanced $6.5 million of 6.7 percent Pollution Control Revenue Bonds and $12.2 million of 7.5 percent Pollution Control Revenue Bonds.

In 2004, our gas marketing subsidiary increased levels of natural gas inventory in storage through the purchases of gas which were sold for forward delivery in the first and second quarters of 2005. At year-end 2004, our natural gas inventory was $63.3 million, compared to $23.4 million at year-end 2003.

Our consolidated net worth was $735.8 million at December 31, 2004, which was approximately $161.7 million in excess of the net worth we are required to maintain under the debt covenant described above. The long-term debt component of our capital structure at December 31, 2004 was 49.9 percent, our total debt leverage ratio was 51.3 percent and our recourse leverage ratio was approximately 46.4 percent.

On January 21, 2005, we purchased CLF&P for approximately $90 million, including the assumption of $25 million of CLF&P outstanding debt. We funded the purchase price of this acquisition with existing cash on hand and short-term borrowings on bank credit facilities.

In addition, Enserco Energy, Inc., our gas marketing unit, has a $150 million uncommitted, discretionary line of credit to provide credit support for the purchase of natural gas. As of December 31, 2004, we had a $3.0 million guarantee to the lender under this facility. At December 31, 2004, there were outstanding letters of credit issued under the facility of $91.7 million with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. (BHER), our crude oil marketing unit, had a $25 million uncommitted, discretionary credit facility at December 31, 2004. The facility allows BHER to elect up to $40 million of available credit via notification to the bank at the beginning of each calendar quarter. This line of credit provides credit support for the purchases of crude oil by BHER. We provided no guarantee to the lender under this facility. At December 31, 2004, BHER had letters of credit outstanding of $8.9 million and no borrowing balance outstanding on its overdraft line.

Our ability to obtain additional financing, if necessary, will depend upon a number of factors, including our future performance and financial results, and capital market conditions. We cannot assure you that we will be able to raise additional capital on reasonable terms or at all.

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2004:

Contractual Obligations	Payments Due by Period (in thousands) Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt [a]	$ 749,747	$ 16,166	$ 337,155[b]	$ 54,387	$ 342,039
Unconditional purchase obligations [c]	230,783	28,429	64,026	35,993	102,335
Operating lease obligations [d]	19,205	2,745	4,331	1,881	10,248
Capital leases [e]	789	195	334	223	37
Other long-term obligations [f]	23,809	—	—	—	23,809
Credit facilities	24,000	24,000	—	—	—
Total contractual cash obligations	$1,048,333	$ 71,535	$ 405,846	$ 92,484	$ 478,468

(a) In addition the following amounts are required for interest payments on long-term debt over the next five years: $39.2 million in 2005, $35.2 million in 2006, $29.6 million in 2007, $27.1 million in 2008 and $26.5 million in 2009.
(b) We expect to refinance maturities on the project financing floating rate debt with project level or corporate level intermediate or long-term debt.
(c) Unconditional purchase obligations include the capacity costs associated with our purchase power agreement with PacifiCorp and certain transmission, communication, gas purchase and gas transportation agreements. The energy charge under the purchase power agreement and the commodity price under the gas purchase contract are variable costs, which for purposes of estimating our future obligations, were calculated using existing prices at December 31, 2004. Our transmission obligations are based on filed tariffs as of December 31, 2004. Actual future costs under the variable rate contracts may differ materially from the estimates used in the above table.
(d) Includes operating leases associated with several office buildings, a storage agreement and land leases associated with the Araphoe, Valmont, Harbor and Ontario power plants.
(e) Represents a lease on computer hardware.
(f) Includes our asset retirement obligations associated with our oil and gas and coal mining segments as discussed in Note 9 to our Notes to Consolidated Financial Statements.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2004, we had guarantees totaling $184.7 million in place. Of the $184.7 million, $139.3 million was related to guarantees associated with subsidiaries' debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets, $20.0 million was related to performance obligations under subsidiary contracts and $25.4 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 22 of our Notes to Consolidated Financial Statements.

As of December 31, 2004, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2004	Year Expiring
Guarantee payments under the Las Vegas Cogen I Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee of certain obligations under Enserco's credit facility	3,000	2005
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	500	2005
Guarantee payments of Black Hills Power under various transactions with Southern California Edison Company	750	2005
Guarantee obligations under the Wygen Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	28,213	2010
Guarantee payments of Las Vegas Cogen II to Nevada Power Company under a power purchase agreement	5,000	2013
Indemnification for subsidiary reclamation/surety bonds	25,420	Ongoing
	$ 184,651	

Credit Ratings

As of February 28, 2005, our issuer credit rating is "Baa3" by Moody's Investors Service and "BBB-" by Standard & Poor's. In addition, our Black Hills Power's first mortgage bonds are rated "Baa1" and "BBB" by Moody's and Standard & Poor's, respectively. Standard & Poor's downgraded our issuer credit rating to "BBB-" in May 2003. This credit rating downgrade had a minimal effect on our interest rates under our credit agreements. These security ratings are subject to revision and/or withdrawal at any time by the respective rating organizations. None of our current credit agreements contain acceleration triggers. If our issuer credit rating should drop below investment grade, however, pricing under the credit agreements would be affected, increasing interest expense by approximately $0.3 million pre-tax based on December 31, 2004 balances.

In addition, as a result of becoming a registered holding company under PUHCA, if our credit ratings drop below investment grade, we would be restricted absent prior SEC approval in the amounts and types of additional investments which we would be allowed to make.

Capital Requirements

Our primary capital requirements for the three years ended December 31, were as follows:

	2004	2003	2002
		(in thousands)	
Property additions and acquisition costs:			
Wholesale energy	$ 63,739	$ 81,271	$ 248,956
Retail services	21,448	33,605	52,903
Corporate	5,787	1,815	1,332
Common stock dividends	40,210	37,025	31,116
Maturities/redemptions of long-term debt	155,021	139,310	32,527
	$ 286,205	$ 293,026	$ 366,834

Our capital additions for 2004 were $91.0 million. The capital expenditures were primarily for maintenance capital and development drilling of oil and gas properties.

Our capital additions for 2003 were $116.7 million. The capital expenditures were primarily for maintenance capital, development drilling of oil and gas properties and the completion of the construction of an AC-DC-AC converter station for Black Hills Power.

Our capital additions for 2002 were $303.2 million. The major capital items for the year included the following:

- Acquisition of additional assets and interests in crude oil pipelines and storage facilities.
- Continuation of the construction of our 224 megawatt gas-fired Las Vegas II power plant located near Las Vegas, Nevada, which was placed into service in January 2003.
- Completion of construction of the 50 megawatt combined-cycle expansion at our Arapahoe site in Denver, Colorado, which was placed into service in October 2002.
- Acquisition of an additional 30 percent interest in the Harbor Cogeneration facility.
- Acquisitions of various interests in partnerships in which we previously held a majority interest.
- Completion of construction of the Lange Combustion Turbine for Black Hills Power, which was placed into service in March 2002.
- Construction of an AC-DC-AC converter station for Black Hills Power, which was placed into service in the fourth quarter of 2003.
- Continuation of the construction of our communications fiber optic network.

Forecasted capital requirements for maintenance capital and developmental capital are as follows:

	2005	2006	2007
		(in thousands)	
Wholesale energy*	$ 52,300	$ 61,840	$ 64,710
Retail services**	136,500	92,680	57,710
Corporate	6,530	1,690	1,770
Unspecified development capital	50,000	55,000	96,190
	$ 245,330	$ 211,210	$ 220,380

* Wholesale energy capital requirements include approximately $38.7 million, $43.9 million and $47.1 million in 2005, 2006 and 2007, respectively, of oil and gas expenditures.

** Retail services regulated utility capital requirements include approximately $90.0 million for the CLF&P acquisition in 2005 and $50.0 million and $18.1 million for the development of a coal-fired plant in 2006 and 2007, respectively.

Market Risk Disclosures

Our activities in the regulated and unregulated energy sector expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and counterparty risk. We have developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks:

- commodity price risk associated with our marketing businesses, our natural length in crude oil and natural gas production, and fuel procurement for our gas fired generation assets; and

- interest rate risk associated with our variable rate credit facilities and our project financing floating rate debt as described in Notes 7 and 8 of our Notes to Consolidated Financial Statements.

Our exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related interest rate and commodity markets.

To manage and mitigate these identified risks, we have adopted the *Black Hills Corporation Risk Policies and Procedures (BHCRPP)*. These policies have been approved by our Executive Risk Committee and reviewed by our Board of Directors. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Executive Risk Committee composed of senior level executives meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Trading Activities

Natural Gas Marketing

We have a natural gas marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the western and mid-continent regions of the United States and Canada. For producer services our main objective is to provide value in the supply chain by acting as the producer’s “marketing arm” for wellhead purchases, scheduling services, imbalance management, risk management services and transportation management. We accomplish this goal through industry experience, extensive contacts, transportation and risk management expertise, trading skills and personal attention. Our origination efforts focus on supplying and providing electricity generators with flexible options to procure their energy inputs and asset optimization services to these large end-use consumers of natural gas. Our wholesale marketing activity has two functions: support the efforts of producer services and end-use origination groups, and marketing third party natural gas.

To effectively manage our producer services, end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial instruments including over-the-counter swaps and options and storage and transportation agreements.

We conduct our gas marketing business activities within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, we permit only limited market risk positions as clearly defined in these policies and procedures.

Monitoring and Reporting Market Risk Exposures

Senior management uses a number of quantitative tools to measure, monitor, and limit our exposure to market risk in our natural gas portfolio. We measure and monitor the market risk inherent in the natural gas trading portfolio employing value-at-risk (VaR) analysis and scenario analysis. VaR is a statistical measure that quantifies the probability and magnitude of potential future losses related to open contract positions. We use scenario analysis to test the impact of extreme moves in both specific delivery points and overall commodity prices on our portfolio value. We also monitor and limit our market risk by establishing limits on the nominal size of positions based on type of trade, location, and duration.

VaR is a statistical measure used to quantify the potential loss in fair value of the trading portfolio over a particular time, with a specified likelihood of occurrence, due to adverse market price changes. We use an external VaR model from a third party vendor and utilize independent commodity pricing data. The modeling of VaR involves a number of assumptions and approximations. Inputs for the VaR calculation include commodity prices, positions, instrument valuations, and variance-covariance matrices. While we believe that our assumptions and approximations are reasonable, there is currently no uniform methodology or best practice for calculating VaR in the energy sector.

We calculate VaR on a daily basis to determine the potential three-day favorable and unfavorable changes to the market value of our portfolio. The VaR is computed utilizing Monte Carlo simulation based on correlation matrices for price movements over a specified period (generally ranging from one to three months) to simulate forward price curves in the natural gas markets to estimate the “worst case” outcomes on the existing portfolio value. The VaR computations utilize a 99 percent loss level for a three day holding period with a 95 percent confidence level. This calculation means that there is a one in one hundred (1 in 100) statistical chance that the portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR over a three day period, provided that no mitigation actions are taken during these three days.

At year-end 2004, we were completing the implementation of an enhanced trade capture system and due to technical constraints, must estimate our VaR. During this system implementation, risk management activities focused upon scrutinizing positions, their changes in daily mark-to-market and other non-statistical risk management techniques. Our estimate of the three-day, 99 percent loss level VaR is approximately $1.7 million.

Actual commodity price volatility can result in portfolio values worse than predicted using the VaR model. The VaR methodology assumes a normal distribution of price changes; thus, if the actual distribution is not normal, the VaR may understate actual results. VaR is used to estimate the risk of the entire gas marketing portfolio. For locations that have insufficient daily trading activity, VaR may not accurately estimate risk due to limited price information. Therefore, stress tests are employed, in addition to VaR, to further measure risk when market price information may prove insufficient. VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of VaR is that past changes in assumed market risk factors may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology’s other limitations.

The contract or notional amounts, terms and mark-to-market values of our natural gas marketing and derivative commodity instruments at December 31, 2004 and 2003, are set forth in Note 2 of our Notes to Consolidated Financial Statements.

The following table provides a reconciliation of the activity in our energy trading portfolio that has been recorded at fair value under a mark-to-market method of accounting during the year ended December 31, 2004 (in thousands):

Total fair value of natural gas marketing marked-to-market at December 31, 2003	$ 1,222[(a)]
Net cash settled during the year on positions that existed at December 31, 2003	(3,454)
Unrealized gain on new positions entered during the year and still existing at December 31, 2004	(73)
Realized gain on positions that existed at December 31, 2003 and were settled during year	1,983
Unrealized loss on positions that existed at December 31, 2003 and still exist at December 31, 2004	(608)
Total fair value of natural gas marketing positions marked-to-market at December 31, 2004	$ (930)[(a)]

(a) The fair value of positions marked-to-market consists of derivative assets/liabilities and natural gas inventory that has been designated as a hedged item and marked-to-market as part of a fair value hedge, as follows (in thousands):

	December 31, 2004	December 31, 2003
Net derivative assets/(liabilities)	$ 8,082	$ (408)
Fair value adjustment recorded in material, supplies and fuel	(9,012)	1,630
	$ (930)	$ 1,222

On January 1, 2003, the Company adopted EITF Issue No. 02-3. The adoption of EITF 02-3 resulted in certain energy trading activities no longer being accounted for at fair value, therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities and our expected cash flows from those operations. EITF 98-10 was superseded by EITF 02-3 and allowed a broad interpretation of what constituted "trading activity" and hence what would be marked-to-market. EITF 02-3 took a much narrower view of what "trading activity" should be marked-to-market, limiting mark-to-market treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. At our natural gas marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in very limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

At December 31, 2004, we had a mark to fair value unrealized loss of $0.9 million for our natural gas marketing activities. Of this amount, $(1.2) million was current and $0.3 million was non-current. The source of fair value measurements were as follows (in thousands):

	Maturities		
Source of Fair Value	2005	2006 and Thereafter	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ 784	$ —	$ 784
Prices provided by other external sources	(1,994)	280	(1,714)
Modeled	—	—	—
Total	$ (1,210)	$ 280	$ (930)

The following table presents a reconciliation of our natural gas marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our natural gas forward book wherein all forward trading positions are marked-to-market. The approach used in determining the non-GAAP measure is consistent with our previous accounting methods under EITF 98-10.

Fair value of our natural gas marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ (930)
Increase/(decrease) in fair value of inventory, storage and transportation positions that are part of our forward trading book, but that are not marked-to-market under GAAP	9,650
Fair value of all forward positions (Non-GAAP)	$ 8,720

Activities Other than Trading

Crude Oil Marketing

We have a crude oil marketing and transportation services company operating predominately in Texas, Oklahoma, and Louisiana. We specialize in providing independent producers with marketing and transportation services to market their crude oil production to end-use markets. Our main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchasing, scheduling services, imbalance management and transportation management.

To provide these services, we execute physical crude oil purchase contracts with producers and resell into various crude oil markets. Through these transactions, we effectively lock in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. We do not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that we identify will be managed and mitigated within the guidelines stipulated in the BHCRPP.

The contract or notional amounts, terms and mark-to-market values of our crude oil contracts at December 31, 2004 and 2003 are set forth in Note 2 of our Notes to Consolidated Financial Statements.

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. These natural "long" positions, or unhedged open positions, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve our cash flows. We have adopted guidelines covering hedging for our natural gas and crude oil production. These guidelines have been approved by our Executive Risk Committee and reviewed by our Board of Directors.

Any hedging strategies are conducted with an enterprise wide perspective. As more fully defined in the next section, we have some fuel procurement risk within our gas-fired generation business. Therefore, hedging in the oil and gas segment considers any natural hedge offsets in the power generation segment. In certain cases, we do not hedge forecasted natural gas production when we have offsetting market risk in our fuel requirements in the power generation segment. In other words, exploration and production's natural length is used to offset generation's short position.

The contract or notional amounts, terms and fair values of our contracts used to hedge portions of our crude oil and natural gas production at December 31, 2004 and 2003 are set forth in Note 2 of our Notes to Consolidated Financial Statements.

To mitigate commodity price risk and preserve cash flows, we use over-the-counter swaps and options.

The Company has entered into agreements to hedge a portion of its estimated 2005 and 2006 natural gas and crude oil production. The hedge agreements in place at December 31, 2004 are as follows:

Natural Gas

Location	Term	Volume (mmbtu/day)	Price
San Juan El Paso	01/05 – 03/05	2,000	$4.80
San Juan El Paso	01/05 – 03/05	2,500	$5.63
San Juan El Paso	01/05 – 03/05	2,500	$7.15
San Juan El Paso	01/05 – 03/05	2,500	$7.24
San Juan El Paso	01/05 – 03/05	2,500	$8.00
San Juan El Paso	04/05 – 10/05	2,500	$5.30
San Juan El Paso	04/05 – 10/05	5,000	$5.40
San Juan El Paso	04/05 – 10/05	2,500	$6.04
San Juan El Paso	11/05 – 03/06	2,500	$7.08
CIG	01/05 – 03/05	2,500	$6.01

Crude Oil

Location	Term	Volume (barrels/month)	Price
NYMEX	Calendar 2005	10,000	$27.90
NYMEX	Calendar 2005	10,000	$34.08
NYMEX	Calendar 2006	10,000	$41.00

Power Generation

We have a portfolio of gas-fired generation assets located throughout several Western states. The output from most of these generation assets are sold under long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some gas-fired generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is our policy that fuel risk, to the extent possible, be hedged. Since we are “long” natural gas in our exploration and production segment, we look at our enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, we may attempt to hedge only enterprise wide “long” or “short” positions.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2004, we had $113.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 1.75 years. Further details of the swap agreements are set forth in Note 2 of our Notes to Consolidated Financial Statements.

On December 31, 2004 and 2003, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2004	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)
Swaps on project financing	$ 113,000	4.22%	1.75	$ 60	$ —	$ 1,226	$ 200	$ (1,366)
December 31, 2003								
Swaps on project financing	$113,000	4.48%	2.75	$ 256	$ —	$ 3,247	$ 1,931	$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	—	—	169	—	(169)
	$ 138,000			$ 256	$ —	$ 3,416	$ 1,931	$ (5,091)

We anticipate a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2005. Based on December 31, 2004 market interest rates, $1.2 million will be realized as additional interest expense during 2005. Estimated and realized amounts will likely change during 2005 as market interest rates change.

At December 31, 2004, we had $366.6 million of outstanding, variable-rate debt of which $253.6 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause interest expense to increase $2.5 million.

The table below presents principal (or notional) amounts and related weighted average interest rates by year of maturity for our short-term investments and long-term debt obligations, including current maturities (in thousands).

	2005	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**
Cash equivalents							
Fixed rate	$ 64,506	$ —	$ —	$ —	$ —	$ —	$ 64,506
Long-term debt							
Fixed rate	$ 2,854	$ 2,865	$ 2,049	$ 2,062	$ 2,078	$371,280	$ 383,188
Average interest rate	8.5%	8.5%	9.6%	9.6%	9.6%	7.3%	7.4%
Variable rate [(a)]	$ 13,312	$197,546	$ 113,468	$ 19,165	$ 2,000	$ 21,068	$ 366,559
Average interest rate	3.9 %	3.5%	3.6%	3.0%	4.0%	3.9%	3.5%
Total long-term debt	$ 16,166	$200,411	$ 115,517	$ 21,227	$ 4,078	$392,348	$ 749,747
Average interest rate	4.7 %	3.5%	3.7 %	3.6 %	6.9%	7.1%	5.5%

(a) Approximately 31 percent of the variable rate long-term debt has been hedged with interest rate swaps moving the floating rates to fixed rates with an average interest rate of 4.22 percent.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy (BHCCP) that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Credit Committee composed of senior executives meets on a regular basis to review the Company’s credit activities and to monitor compliance with the policies adopted by the Company.

For our energy marketing, production, and generation activities, we attempt to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer’s current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot assure you that we will continue to experience the same credit loss rates that we have in the past or that an investment grade counterparty will not default sometime in the future.

At the end of the year, our credit exposure (exclusive of retail customers of our regulated utility and communications segment) was concentrated with investment grade companies. Approximately 74 percent of our credit exposure was with investment grade companies. For the 26 percent credit exposure with non-investment grade rated counterparties, approximately 91 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

Foreign Exchange Contracts

Our gas marketing subsidiary conducts its business in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars, which creates exchange rate risk. To mitigate this risk, we enter into forward currency exchange contracts to offset earnings volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2004, we had outstanding forward exchange contracts to sell approximately $38.0 million Canadian dollars and at December 31, 2003, had no forward exchange contracts. At December 31, 2004 and 2003, we also had outstanding forward exchange contracts to purchase approximately $10.8 million and $3.0 million Canadian dollars, respectively. These contracts had a fair value of $(1.0) million and $0.1 million at December 31, 2004 and 2003, respectively, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2004 settle by April 2005.

New Accounting Pronouncements

See Note 1 of our Notes to Consolidated Financial Statements for information on new accounting standards adopted in 2004 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2004, based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation we have concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Black Hills Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Black Hills Corporation and subsidiaries (the "Corporation") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Corporation maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in the COSO Framework. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in the COSO Framework.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2004, of the Corporation, and our report dated March 10, 2005, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, and Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities*, effective January 1, 2003; Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities*, effective December 31, 2003; and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, effective January 1, 2002.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Black Hills Corporation

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Corporation") as of December 31, 2004 and 2003, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Black Hills Corporation and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 10, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Corporation's internal control over financial reporting and an unqualified opinion on the effectiveness of the Corporation's internal control over financial reporting.

As discussed in Note 9 and Note 2, respectively, to the consolidated financial statements, effective January 1, 2003, the Corporation adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, and Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities.* As discussed in Note 6 to the consolidated financial statements, effective December 31, 2003, the Corporation adopted Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities*. As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, the Corporation adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2005

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2004	2003	2002
	(in thousands, except per share amounts)		
Revenues:			
Operating revenues	$1,121,701	$1,136,050	$ 908,477
Contract termination revenue	—	114,000	—
	1,121,701	1,250,050	908,477
Operating expenses:			
Fuel and purchased power	703,261	718,450	580,973
Operations and maintenance	99,371	99,335	68,257
Administrative and general	68,859	73,548	64,673
Depreciation, depletion and amortization	87,833	80,791	63,865
Taxes, other than income taxes	28,458	29,551	17,993
Impairment of long-lived assets	—	117,207	—
	987,782	1,118,882	795,761
Operating income	133,919	131,168	112,716
Other income (expense):			
Interest expense	(51,842)	(52,579)	(33,564)
Interest income	1,758	1,076	609
Other expense	(491)	(539)	(554)
Other income	1,181	1,209	3,264
	(49,394)	(50,833)	(30,245)
Income from continuing operations before minority interest, income taxes and change in accounting principle	84,525	80,335	82,471
Equity in earnings of unconsolidated subsidiaries	(386)	5,747	4,588
Minority interest	(186)	—	(2,277)
Income taxes	(26,704)	(29,601)	(26,644)
Income from continuing operations before changes in accounting principles	57,249	56,481	58,138
Income from discontinued operations, net of income taxes	724	9,936	2,418
Changes in accounting principles, net of income taxes	—	(5,195)	896
Net income	57,973	61,222	61,452
Preferred stock dividends	(321)	(258)	(223)
Net income available for common stock	$ 57,652	$ 60,964	$ 61,229
Earnings per share of common stock:			
Basic-			
Continuing operations	$ 1.76	$ 1.84	$ 2.16
Discontinued operations	0.02	0.33	0.09
Changes in accounting principles	—	(0.17)	0.03
Total	$ 1.78	$ 2.00	$ 2.28
Diluted-			
Continuing operations	$ 1.74	$ 1.82	$ 2.14
Discontinued operations	0.02	0.32	0.09
Changes in accounting principles	—	(0.17)	0.03
Total	$ 1.76	$ 1.97	$ 2.26
Weighted average common shares outstanding:			
Basic	32,387	30,496	26,803
Diluted	32,912	31,015	27,167

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2004	2003
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 64,506	$ 172,759
Restricted cash	3,069	1,350
Accounts receivable (net of allowance for doubtful accounts of $4,698 and $7,345, respectively)	256,505	201,976
Materials, supplies and fuel	89,732	44,895
Derivative assets	47,977	26,804
Deferred income taxes	4,237	4,256
Prepaid income taxes	3,978	18,940
Notes receivable	239	554
Other current assets	7,005	8,321
Assets of discontinued operations	3,059	4,575
	480,307	484,430
Investments	24,436	26,847
Property, plant and equipment	1,971,119	1,882,545
Less accumulated depreciation and depletion	(525,387)	(440,274)
	1,445,732	1,442,271
Other assets:		
Goodwill	30,144	30,144
Intangible assets, net	36,750	40,070
Derivative assets	593	1,002
Other	38,201	38,488
	105,688	109,704
	$ 2,056,163	$ 2,063,252
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 196,619	$ 162,706
Accrued liabilities	69,306	66,618
Derivative liabilities	43,206	32,967
Notes payable	24,000	—
Current maturities of long-term debt	16,166	17,659
Accrued income taxes	7,799	5,752
Liabilities of discontinued operations	651	3,444
	357,747	289,146
Long-term debt, net of current maturities	733,581	868,459
Deferred credits and other liabilities:		
Deferred income taxes	159,623	125,040
Derivative liabilities	206	3,247
Other	64,406	62,924
	224,235	191,211
Minority interest	4,835	4,689
Commitments and contingencies (Notes 8, 16, 20, 21 and 22)		
Stockholders' equity:		
Preferred stock – no par Series 2000-A; 21,500 shares authorized; issued and outstanding: 6,839 and 7,771 respectively	7,167	8,143
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 32,595,285 shares in 2004 and 32,447,765 shares in 2003	32,595	32,448
Additional paid-in capital	384,439	379,271
Retained earnings	322,009	304,567
Treasury stock at cost – 117,567 shares in 2004 and 150,048 shares in 2003	(2,838)	(3,560)
Accumulated other comprehensive loss	(7,607)	(11,122)
	728,598	701,604
Total stockholders' equity	735,765	709,747
	$ 2,056,163	$ 2,063,252

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2004	2003	2002
		(in thousands)	
Operating activities:			
Net income available for common	$ 57,652	$ 60,964	$ 61,229
Adjustments to reconcile net income available for common to net cash provided by operating activities-			
Income from discontinued operations	(724)	(9,936)	(2,418)
Depreciation, depletion and amortization	87,833	80,791	63,865
Impairment of long-lived assets	—	117,207	—
Issuance of treasury stock for operating expense	1,030	361	2,252
Change in provision for valuation allowances	(2,598)	3,363	(2,935)
Net change in derivative assets and liabilities	(8,101)	(317)	(2,086)
Deferred income taxes	29,186	(3,743)	33,597
Undistributed earnings in associated companies	3,762	(3,874)	(2,972)
Minority interest	186	—	2,277
Accounting changes	—	5,195	(896)
Change in operating assets and liabilities-			
Accounts receivable and other current assets	(75,620)	(75,673)	(74,806)
Accounts payable and other current liabilities	34,061	(6,863)	128,209
Other operating activities	10,015	3,206	7,670
	136,682	170,681	212,986
Investing activities:			
Property, plant and equipment additions	(90,974)	(90,353)	(232,347)
Proceeds from sale of assets	—	185,926	—
Payment for acquisition of net assets, net of cash acquired	—	—	(23,229)
Payment for acquisition of minority interest	—	(9,000)	(13,800)
Increase in notes receivable – Mallon Resources	—	(5,164)	(33,815)
Other investing activities	(1,892)	(3,566)	(5,300)
	(92,866)	77,843	(308,491)
Financing activities:			
Dividends paid on common stock	(40,210)	(37,025)	(31,116)
Common stock issued	4,031	123,073	5,084
Increase (decrease) in short-term borrowings, net	24,000	(340,500)	(19,500)
Long-term debt – issuance	18,650	252,000	223,135
Long-term debt – repayments	(155,021)	(139,310)	(25,069)
Other financing activities	(3,519)	(8,924)	(8,312)
	(152,069)	(150,686)	144,222
Increase (decrease) in cash and cash equivalents	(108,253)	97,838	48,717
Cash and cash equivalents:			
Beginning of year	172,759	74,921	26,204
End of year	$ 64,506	$ 172,759	$ 74,921
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 49,546	$ 51,452	$ 41,404
Income taxes paid (refunded)	$ (21,927)	$ 58,660	$ (31,353)
Non-cash net assets acquired through issuance of common and preferred stock (Note 21)	$ —	$ 6,231	$ 3,826
Property, plant and equipment acquired with accrued liabilities and the issuance of long-term debt	$ —	$ 6,951	$ —
Non-cash net assets of Mallon Resources, acquired through issuance of common stock and decrease in notes receivable (Note 24)	$ —	$ 51,153	$ —

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME

	Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Accumulated Other Comprehensive Income(loss)	Total
	Shares	Amount			Shares	Amount		
				(in thousands)				
Balance at December 31, 2001	26,891	$26,891	$241,454	$250,515	239	$(5,503)	$ (3,742)	$509,615
Comprehensive Income:								
Net income	--	--	--	61,452	--	--	--	61,452
Other comprehensive loss, net of tax (see Note 18)	--	--	--	--	--	--	(17,450)	(17,450)
Total comprehensive income	--	--	--	61,452	--	--	(17,450)	44,002
Dividends on preferred stock	--	--	--	(223)	--	--	--	(223)
Dividends on common stock	--	--	--	(31,116)	--	--	--	(31,116)
Issuance of common stock	211	211	4,993	--	--	--	--	5,204
Treasury stock issued, net	--	--	550	--	(70)	1,582	--	2,132
Balance at December 31, 2002	27,102	27,102	246,997	280,628	169	(3,921)	(21,192)	529,614
Comprehensive Income:								
Net income	--	--	--	61,222	--	--	--	61,222
Other comprehensive income, net of tax (see Note 18)	--	--	--	--	--	--	10,070	10,070
Total comprehensive income	--	--	--	61,222	--	--	10,070	71,292
Dividends on preferred stock	--	--	--	(258)	--	--	--	(258)
Dividends on common stock	--	--	--	(37,025)	--	--	--	(37,025)
Issuance of common stock	5,346	5,346	130,484	--	--	--	--	135,830
Treasury stock issued, net	--	--	1,790	--	(19)	361	--	2,151
Balance at December 31, 2003	32,448	32,448	379,271	304,567	150	(3,560)	(11,122)	701,604
Comprehensive Income:								
Net income	--	--	--	57,973	--	--	--	57,973
Other comprehensive income, net of tax (see Note 18)	--	--	--	--	--	--	3,515	3,515
Total comprehensive income	--	--	--	57,973	--	--	3,515	61,488
Dividends on preferred stock	--	--	--	(321)	--	--	--	(321)
Dividends on common stock	--	--	--	(40,210)	--	--	--	(40,210)
Issuance of common stock	147	147	4,860	--	--	--	--	5,007
Treasury stock issued, net	--	--	308	--	(32)	722	--	1,030
Balance at December 31, 2004	32,595	$32,595	$384,439	$322,009	118	$(2,838)	$ (7,607)	$728,598

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a registered public utility holding company and with its subsidiaries operates in two primary operating groups: non-regulated wholesale energy and retail services. The Company operates its wholesale energy businesses through its direct and indirect subsidiaries: Wyodak Resources related to coal, Black Hills Exploration and Production related to oil and natural gas production, Enserco Energy related to natural gas marketing and Black Hills Energy Resources related to crude oil marketing and transportation, and Black Hills Generation and its subsidiaries and Black Hills Wyoming related to independent power activities, all aggregated for reporting purposes as Black Hills Energy. Retail services include public utility electric operations through its subsidiary, Black Hills Power, Inc.; and communications operations through its subsidiaries Black Hills Fiber Systems and Black Hills FiberCom L.L.C. In addition, on January 21, 2005, the Company expanded its retail services with the acquisition of Cheyenne Light, Fuel and Power (see Note 25). For further descriptions of the Company's business segments, see Note 23.

In 2004, the Company sold its subsidiary, Landrica Development Corp., which held land and coal enhancement facilities. In 2003, the Company sold its hydroelectric power plants located in Upstate New York. The non-strategic assets were sold effective September 30, 2003. Amounts related to Landrica and the hydroelectric power plants are included in Discontinued operations on the accompanying Consolidated Financial Statements.

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, inventory obsolescence, realization of market value of derivatives due to commodity risk, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, employee benefit plans, environmental accruals and contingencies. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly owned and majority-owned subsidiaries. In addition, as of December 31, 2003, the Company consolidated Wygen Funding, Limited Partnership, a variable interest entity in which the Company is the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities Revised" (FIN 46-R). Generally, the Company uses equity accounting for investments of which it owns between 20 and 50 percent and investments in partnerships under 20 percent if the Company exercises significant influence.

All significant intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with intercompany fuel sales in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Total intercompany fuel sales not eliminated were $9.6 million, $10.3 million and $10.5 million in 2004, 2003 and 2002, respectively.

The Company's consolidated statements of income include operating activity of acquired companies beginning with their acquisition date.

The Company uses the proportionate consolidation method to account for its working interests in oil and gas properties and for its ownership in the jointly owned Black Hills Power transmission tie, the Wyodak power plant and the Black Hills Exploration and Production gas processing plant as discussed in Note 5.

Minority Interest in Subsidiaries

Minority interest in the accompanying Consolidated Statements of Income represents the share of income or loss of certain consolidated subsidiaries attributable to the minority shareholders of those subsidiaries. The minority interest in the accompanying Consolidated Balance Sheets reflect the amount of the underlying net assets of those certain consolidated subsidiaries attributable to the minority shareholders in those subsidiaries.

Earnings attributable to minority ownership in certain subsidiaries are generally shown on the accompanying consolidated statement of income on a pre-tax basis as the subsidiaries with minority investors are typically limited liability companies or partnerships which pay no tax at the corporate or partnership level.

Regulatory Accounting

The Company's subsidiary, Black Hills Power, is 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). These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

Black Hills Power follows the provisions of SFAS 71, and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating Black Hills Power. A 50-year depreciable life for the Neil Simpson II plant is used for financial reporting purposes. If Black Hills Power were not a regulated utility following SFAS 71, a 35 to 40 year life would likely be more appropriate, which would increase depreciation expense by $0.6 - $1.1 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to Black Hills Power's generation operations. In the event Black Hills Power 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. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict Black Hills Power'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 that the continuing application of SFAS 71 is appropriate.

At December 31, 2004 and 2003, the Company had regulatory assets of $7.2 million and $4.6 million and regulatory liabilities of $6.0 million and $6.3 million, respectively. Regulatory assets are primarily recorded for the probable future revenue to recover future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and for unamortized loss on reaquired debt. 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 and also the cost of removal for utility plant, recovered through the Company's electric utility rates. The regulatory assets are included in Other assets and the regulatory liabilities are included in Other deferred credits and other liabilities on the Consolidated Balance Sheets.

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

As of December 31, 2004, the following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets:

	2004	2003
	(in thousands)	
Major Classification		
Materials and supplies	$ 22,661	$ 18,920
Fuel for generation	2,211	1,581
Gas and oil held by energy marketing	64,860	24,394
Total materials, supplies and fuel	$ 89,732	$ 44,895

“Materials and supplies” and “Fuel for generation” are stated at the lower of cost or market. Generally, cost for these classifications is determined on a weighted-average cost methodology.

“Gas and oil held by energy marketing” primarily consists of gas held in storage and gas imbalances held on account with pipelines. Gas imbalances represent the differences that arise between volumes of gas received into the pipeline versus gas delivered off of the pipeline. Generally, natural gas inventory is stated at the lower of cost or market on a weighted-average cost basis. To the extent that inventory has been designated as the underlying hedged item in a “fair value” hedge transaction, those volumes are stated at market value using published spot industry quotations.

Derivatives and Hedging Activities

The Company accounts for its derivative and hedging activities in accordance with 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, must be recognized currently in earnings.

Currency Adjustments

The Company’s natural gas marketing subsidiary, Enserco, engages in business transactions in Canada and accordingly, has various transactions that have been denominated in Canadian dollars. These Canadian denominated transactions/balances are adjusted to United States dollars for financial reporting purposes using the year-end exchange rate for balance sheet items and an average exchange rate during the period for income statement items. Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Consolidated Statement of Income as incurred.

Deferred Financing Costs

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

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is an allowance for funds used during construction (AFUDC) which represents the approximate composite cost of borrowed funds and a return on capital used to finance the project. The AFUDC was computed at an annual composite rate of 9.8 percent during 2004 and 2003 and 9.1 percent during 2002, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $0.2 million, $0.4 million and $11.5 million in 2004, 2003 and 2002, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are computed on a straight-line or componentization basis. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves.

Oil and Gas Operations

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a units-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized.

Under the full cost method, net capitalized costs are subject to a “ceiling test” which limits these costs to the present value of future net cash flows discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on end-of-period spot market prices adjusted for contracted price changes. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period unless subsequent market price changes eliminate or reduce the indicated write-down. Given the volatility of oil and gas prices, the Company’s estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that a write-down of oil and gas properties could occur in the future. No “ceiling test” write-downs were recorded during 2004, 2003 or 2002.

Goodwill and Intangible Assets

In June 2001, the FASB issued SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The amortization provisions of SFAS 142 apply to goodwill and intangible assets acquired after June 30, 2001. With respect to goodwill and intangible assets acquired prior to July 1, 2001, the Company was required to adopt SFAS 142 effective January 1, 2002. The cumulative effect adjustment recognized upon adoption of SFAS 142 was $0.1 million (after-tax), which had only a nominal impact on earnings per share. The adjustment consisted of income from the after-tax write-off of negative goodwill from prior acquisitions in the power generation segment of $0.9 million, offset by a $0.8 million after-tax write-off for the impairment of goodwill related to the discontinued coal marketing operations (see Note 19). The goodwill impairment was a result of changes in the criteria for the measurement of impairments from an undiscounted to a discounted cash flow method. If the carrying value exceeds the fair value, an impairment loss will be recognized. A discounted cash flow approach was used to determine fair value of the Company’s businesses for the purposes of testing for impairment.

The substantial majority of the Company's goodwill and intangible assets are contained within the Power Generation segment. Changes to goodwill and intangible assets during the years ended December 31, 2004 and 2003 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2002, net of accumulated amortization	$ 23,913	$ 78,089
Additions	6,231	62
Impairment losses	—	(34,094)
Amortization expense	—	(3,987)
Balance at December 31, 2003, net of accumulated amortization	30,144	40,070
Amortization expense	—	(3,320)
Balance at December 31, 2004, net of accumulated amortization	$ 30,144	$ 36,750

Intangible assets primarily relate to site development fees and above-market long-term contracts within the Power Generation segment and are amortized using a straight-line method using estimated useful lives ranging from 5 to 40 years. Intangible assets totaled $58.5 million, with accumulated amortization of $21.7 million at December 31, 2004 and $58.5 million, with accumulated amortization of $18.4 million at December 31, 2003. Amortization expense for intangible assets was $3.3 million, $4.0 million and $4.2 million in 2004, 2003 and 2002, respectively. Amortization expense for existing intangible assets for the next five years is expected to be approximately $3.3 million a year.

During the third quarter of 2003, the Company wrote off intangible assets of $34.1 million, net of accumulated amortization of $1.1 million, related to the impairment of the Las Vegas II plant. The impairment charge is a result of a contract termination and subsequent impairment of the Las Vegas II plant (see Notes 13 and 14).

Goodwill additions during the year ended December 31, 2003 were from contingent consideration related to the July 7, 2000 acquisition of Indeck Capital Inc. (see Note 11).

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. In 2004, a $1.1 million pre-tax impairment was recorded to reduce the carrying value of the Company's Pepperell power plant. This charge is reported in discontinued operations. In 2003, a $117.2 million pre-tax impairment was recorded to reduce the carrying value of the Las Vegas II facility. In 2002, a $0.8 million pre-tax impairment was recorded for intangible assets in the discontinued coal marketing operations.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. Income taxes for consolidated subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss.

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

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. In addition, energy marketing businesses have historically used the mark-to-market method of accounting. Under that method, all energy marketing activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In accordance with Emerging Issues Task Force (EITF) Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), all energy marketing contracts entered into after October 25, 2002 that do not meet the definition of derivatives as defined by SFAS 133, have been accounted for under the accrual method of accounting. For long-term non-utility power sales agreements revenue is recognized either in accordance with EITF No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts" (EITF 91-6), or in accordance with SFAS No. 13, "Accounting for Leases," (SFAS 13) as appropriate. Under EITF 91-6, revenue is generally recognized as the lower of the amount billed or the average rate expected over the life of the agreement. Under SFAS 13, revenue is generally levelized over the life of the agreement. Revenues from one-year advertising contracts in telephone directories published by our Communications segment are recognized on the publication date with cash received prior to publication deferred until it is recognized. For its Investment in Associated Companies (see Note 3), which are involved in power generation, the Company uses the equity method to recognize as earnings its pro rata share of the net income or loss of the associated company.

The Company presents its operating revenues from energy marketing operations in accordance with the guidance provided in EITF 02-3 and EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" (EITF 99-19). Accordingly, gains and losses (realized and unrealized) on transactions at our natural gas marketing operations are presented on a net basis in operating revenues, whether or not settled physically. Settled amounts on contracts at our crude oil marketing operations are reported on a gross basis as they are not held for "trading purposes" as defined by EITF 02-3 and EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and not "held for trading purposes" as defined by Issue No. 02-3."

Earnings Per Share of Common Stock

Basic earnings per share from continuing operations is computed by dividing "Income from continuing operations before change in accounting principle" less preferred dividends, by the weighted average number of common shares outstanding during each year. Diluted earnings per share gives effect to all dilutive potential common shares outstanding during a period. A reconciliation of income from continuing operations and basic and diluted share amounts is as follows (in thousands):

	2004		2003		2002	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 57,249		$ 56,481		$ 58,138	
Less: preferred stock dividends	(321)		(258)		(223)	
Basic – Income from continuing operations	56,928	32,387	56,223	30,496	57,915	26,803
Dilutive effect of:						
Stock options	—	96	—	102	—	91
Convertible preferred stock	321	195	258	222	223	148
Estimated contingent shares issuable for prior acquisition	—	159	—	158	—	88
Others	—	75	—	37	—	37
Diluted – Income from continuing operations	$ 57,249	32,912	$ 56,481	31,015	$ 58,138	27,167

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	2004	2003	2002
Options to purchase common stock	484	334	381
Restricted stock	—	21	34
	484	355	415

Stock-based Compensation

At December 31, 2004, the Company has three stock-based employee compensation plans under which it can issue stock options to its employees, which are described more fully in Note 10. The Company accounts for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123), to stock-based employee compensation as of December 31 (in thousands, except per share amounts):

	2004	2003	2002
Net income available for common stock, as reported	$ 57,652	$ 60,964	$ 61,229
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(665)	(794)	(990)
Pro forma net income	$ 56,987	$ 60,170	$ 60,239
Earnings per share:			
As reported –			
Basic			
Continuing operations	$ 1.76	$ 1.84	$ 2.16
Discontinued operations	0.02	0.33	0.09
Change in accounting principles	—	(0.17)	0.03
Total	$ 1.78	$ 2.00	$ 2.28
Diluted			
Continuing operations	$ 1.74	$ 1.82	$ 2.14
Discontinued operations	0.02	0.32	0.09
Change in accounting principles	—	(0.17)	0.03
Total	$ 1.76	$ 1.97	$ 2.26
Pro forma –			
Basic			
Continuing operations	$ 1.74	$ 1.81	$ 2.13
Discontinued operations	0.02	0.33	0.09
Change in accounting principles	—	(0.17)	0.03
Total	$ 1.76	$ 1.97	$ 2.25
Diluted			
Continuing operations	$ 1.72	$ 1.80	$ 2.11
Discontinued operations	0.02	0.32	0.09
Change in accounting principles	—	(0.17)	0.03
Total	$ 1.74	$ 1.95	$ 2.23

Reclassifications

Certain 2003 and 2002 amounts in the consolidated financial statements have been reclassified to conform to the 2004 presentation. These reclassifications had no effect on the Company's stockholders' equity or results of operations, as previously reported.

Recently Adopted Accounting Pronouncements

FSP 106-2

In May 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), which provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act) for employers that sponsor postretirement healthcare plans that provide prescription drug benefits. If the Plan is deemed actuarially equivalent to the prescription drug benefit under the 2003 Medicare Act, the sponsor of the Plan could be eligible for a federal subsidy. FSP 106-2 supersedes FSP 106-1 that was issued in January 2004 under the same title. FSP 106-2 is effective for the first interim period beginning after June 15, 2004. The Company provides prescription drug benefits to certain eligible employees. The actuarial measurement of the accumulated postretirement benefit obligation and net periodic postretirement benefit cost does not include the effects of the 2003 Medicare Act as it is believed the Plan is not actuarially equivalent (see Note 20).

FSP FAS 141-1 and FAS 142-1

In April 2004, the FASB issued FSP FAS 141-1 and FAS 142-1, "Interaction of FASB Statements No. 141, *Business Combinations*, and No. 142, *Goodwill and Other Intangible Assets*, and EITF Issue No. 04-2, *Whether Mineral Rights Are Tangible or Intangible Assets*." The FSP amends SFAS 141 and SFAS 142 to conform with the EITF consensus in EITF 04-2 that mineral rights, as defined by EITF 04-2, are tangible assets. When the Company adopted SFAS 142 on January 1, 2002, the amounts related to mineral rights were already classified as tangible assets and continue to be classified in "Property, plant and equipment" on the accompanying Consolidated Balance Sheets. The adoption of FSP FAS 141-1 and FAS 142-1 had no effect on the Company's consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

SFAS No. 123 (Revised 2004)

In December 2004, the FASB issued SFAS No. 123 (Revised 2004) "Share Based Payment" (SFAS 123 (Revised 2004)). SFAS 123 (Revised 2004) requires the measurement and recognition of the cost of employee services received in exchange for an award of equity instruments, based on the grant-date fair value of the award. The cost is to be recognized over the requisite service period. The effective date of SFAS 123 (Revised 2004) is the first interim period beginning after June 15, 2005. The Company currently accounts for its employee equity compensation stock option plans under the provisions of APB No. 25 and no stock-based employee compensation cost is reflected in net income (see Note 1, Stock-Based Compensation and Note 10 Common Stock). The effect of adoption of SFAS 123 (Revised 2004) will be to recognize compensation expense for the fair value of the stock options granted at the grant date. Total stock-based employee compensation expense, net of related tax effects would have been $0.7 million in 2004, $0.8 million in 2003 and $1.0 million in 2002 had the Company applied the fair value recognition provisions of SFAS 123 during those periods.

(2) RISK MANAGEMENT ACTIVITIES

The Company's activities in the regulated and unregulated energy sector expose it to a number of risks in the normal operations of its businesses. Depending on the activity, the Company is exposed to varying degrees of market risk and counterparty risk. The Company has developed policies, processes, systems, and controls to manage and mitigate these risks.

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. The Company is exposed to the following market risks:

- commodity price risk associated with its marketing businesses, its natural length in crude oil and natural gas production, and fuel procurement for its gas fired generation assets;
- interest rate risk associated with variable rate credit facilities and project financing floating rate debt as described in Notes 7 and 8; and
- foreign currency exchange risk associated with natural gas marketing business transacted in Canadian dollars.

The Company's exposure to these market risks is affected by a number of factors including the size, duration, and composition of our energy portfolio, the absolute and relative levels of interest rates, currency exchange rates and commodity prices, the volatility of these prices and rates, and the liquidity of the related markets.

To manage and mitigate these identified risks, the Company has adopted the *Black Hills Corporation Risk Policies and Procedures (BHCRPP)*. These policies have been approved by the Company's Executive Risk Committee and reviewed by the Board of Directors. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Company has an Executive Risk Committee composed of senior level executives that meets on a regular basis to review the Company's business and credit activities and to ensure that these activities are conducted within the authorized policies.

Trading Activities

Natural Gas Marketing

To effectively manage our marketing portfolios, the Company enters into forward physical commodity contracts, financial instruments including over-the-counter swaps and options, transportation agreements and forward foreign exchange contracts.

Gas marketing business activities are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, only limited market risk positions are permitted, as clearly defined in these policies and procedures. Therefore, a significant majority of the Company's gas marketing positions are fully hedged. The Company attempts to balance its portfolio in terms of volume and timing of performance and delivery obligations.

The Company's natural gas marketing operations fall under the purview of EITF 02-3, SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. As such, all natural gas contracts entered into on or before October 25, 2002 and contracts entered after that date that meet the definition of a derivative as defined by SFAS 133, are accounted for under mark-to-market accounting. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Consolidated Statements of Income.

For the years ended December 31, 2004 and 2003, contracts and other activities at the Company's natural gas marketing operations are accounted for under the provisions of EITF 02-3 and SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). As such, all of the contracts and other activities at the Company's natural gas marketing operations that meet the definition of a derivative under SFAS 133 are accounted for at fair value. EITF 02-3, adopted on January 1, 2003, precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to SFAS 133. The prior authoritative accounting guidance applied was EITF Issue 98-10 "Accounting for Contracts Involving Energy Trading and Risk Management Activities" (EITF 98-10), which allowed a broad interpretation of what constituted "trading activity" and hence what would be marked-to-market. EITF 02-3 took a much narrower view of what "trading activity" should be marked-to-market, limiting mark-to-market treatment primarily to only those contracts that meet the definition of a derivative under SFAS 133. At the Company's natural gas marketing operations, management often employs strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of the Company's producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when the Company is able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow the Company to mark inventory, transportation or storage positions to market. The result is that while a significant majority of the Company's natural gas marketing positions are economically hedged, the Company is required to mark some parts of its overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of its economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

The contract or notional amounts and terms of our natural gas marketing and derivative commodity instruments at December 31, are set forth below:

	2004		2003	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu's)				
Natural gas basis swaps purchased	24,942	15	13,028	12
Natural gas basis swaps sold	27,145	15	12,691	12
Natural gas fixed-for-float swaps purchased	27,274	15	19,645	18
Natural gas fixed-for-float swaps sold	32,206	12	21,752	18
Natural gas physical purchases	64,799	15	50,757	27
Natural gas physical sales	95,996	58	44,066	27
Natural gas options purchased	9,643	33	—	—
Natural gas options sold	9,613	33	—	—
(thousands of U.S. dollars)				
Canadian dollars purchased	$ 10,800	1	$ 3,000	1
Canadian dollars sold	$38,000	4	$ —	—

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2004 and 2003, and the gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income as of December 31, 2004 and 2003 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (loss)
December 31, 2004	$ 46,177	$ 286	$ 38,375	$ 6	$ 8,082
December 31, 2003	$ 26,376	$ 1,002	$ 26,495	$ 1,291	$ (408)

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a “fair value” hedge transaction. These volumes are stated at market value using published spot industry quotations. Market adjustments are recorded in inventory on the Balance Sheet and unrealized gain/loss on the Statement of Income. As of December 31, 2004 and 2003, the market adjustments recorded in inventory were $(9.0) million and $1.6 million, respectively.

Activities Other than Trading

Crude Oil Marketing

The Company’s crude oil marketing operations executes physical crude oil purchase contracts with producers and resells into various crude oil markets. Through these transactions, the Company effectively locks in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. The Company does not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that the Company identifies will be managed and mitigated within the guidelines stipulated in the BHCRPP.

The Company’s crude oil marketing operations had historically fallen under the purview of EITF 98-10 and as such, all crude oil contracts entered into on or before October 25, 2002, had been accounted for under mark-to-market accounting. The net gains or losses have been recorded as Operating revenues in the accompanying Consolidated Statements of Income. With the adoption of EITF 02-3, the contracts entered into at the Company’s crude oil marketing operations either do not meet the definition of derivatives under SFAS 133 or have been exempted from mark-to-market accounting as normal purchase or normal sales contracts as allowed by SFAS 133. Accordingly, none of these contracts entered into after October 25, 2002 are marked-to-market.

The contract or notional amounts and terms of our crude oil contracts at December 31, are set forth below:

	2004		2003	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of barrels)				
Crude oil purchased	1,669	1.0	2,688	0.5
Crude oil sold	1,651	1.0	2,253	0.5

As of December 31, 2004 and 2003, all of the Company’s crude oil marketing contracts are accounted for under the accrual method of accounting.

Oil and Gas Exploration and Production

The Company produces natural gas and crude oil through its exploration and production activities. These natural “long” positions, or unhedged open positions, introduce commodity price risk and variability in its cash flows. The Company employs risk management methods to mitigate this commodity price risk and preserve cash flows. The Company has adopted guidelines covering hedging for its natural gas and crude oil production. These guidelines have been approved by the Company’s Executive Risk Committee, and are routinely reviewed by its Board of Directors.

To mitigate commodity price risk and preserve cash flows, over-the-counter swaps and options are used. These derivative instruments fall under the purview of SFAS 133 and the Company elects to utilize hedge accounting as allowed under this Statement.

At December 31, 2004 and 2003, the Company had a portfolio of swaps to hedge portions of its crude oil and natural gas production. These transactions were previously identified as cash flow hedges, properly documented and initially met prospective effectiveness testing. At year-end, these transactions met retrospective effectiveness testing criteria and retained their cash flow hedge status.

At December 31, 2004 and 2003, the derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On December 31, 2004 and 2003 the Company had the following swaps and related balances (in thousands):

December 31, 2004	Notional	Maximum Duration in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Earnings (Loss)
Crude oil swaps	360,000	1.00	$ —	$ 152	$ 3,112	$ —	$ (2,886)	$ (74)
Natural gas swaps	3,810,000	0.50	1,710	155	493	—	1,372	—
			$ 1,710	$ 307	$ 3,605	$ —	$ (1,514)	$ (74)
December 31, 2003								
Crude oil swaps	360,000	1.00	$ —	$ —	$ 1,445	$ —	$ (1,384)	$ (61)
Natural gas swaps	4,830,000	1.25	172	—	1,611	25	(1,462)	(2)
			$ 172	$ —	$ 3,056	$ 25	$ (2,846)	$ (63)

*Crude in bbls, gas in MMBtu’s

Most of the Company’s crude oil and natural gas hedges are highly effective, resulting in very little earnings impact prior to realization. The Company estimates a portion of the unrealized earnings gains or losses currently recorded in accumulated other comprehensive income will be realized in earnings during 2005. Based on December 31, 2004 market prices, a $1.8 million loss will be realized and reported in earnings during 2005. These estimated realized losses for 2005 were calculated using December 31, 2004 market prices. Estimated and actual realized losses will likely change during 2005 as market prices change.

Power Generation

The Company has a portfolio of natural gas fueled generation assets located throughout several western states. Most of these generation assets are locked into long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some natural gas fueled generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is the Company's policy that fuel risk, to the extent possible, be hedged. Since the Company is "long" natural gas in its exploration and production company, the Company looks at its enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, the Company attempts to hedge only enterprise wide "long" or "short" positions.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, the Company restricts wholesale off-system sales to amounts by which the Company's anticipated generating capabilities exceed its anticipated load requirements plus a required reserve margin.

Financing Activities

The Company engages in activities to manage risks associated with changes in interest rates. The Company has entered into floating-to-fixed interest rate swap agreements to reduce its exposure to interest rate fluctuations associated with its floating rate debt obligations. At December 31, 2004, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2004, the Company had $113.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 1.75 years and a fair value of $(1.4) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2004 and 2003 the Company's interest rate swaps and related balances were as follows (in thousands):

December 31, 2004	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)
Swaps on project financing	$113,000	4.22%	1.75	$ 60	$ —	$ 1,226	$ 200	$ (1,366)
December 31, 2003								
Swaps on project financing	$113,000	4.48%	2.75	$ 256	$ —	$ 3,247	$ 1,931	$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	—	—	169	—	(169)
	$138,000			$ 256	$ —	$ 3,416	$ 1,931	$ (5,091)

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2005. Based on December 31, 2004 market interest rates, $1.2 million will be realized as additional interest expense during 2005. Estimated and realized amounts will likely change during 2005 as market interest rates change.

At December 31, 2004, the Company had $366.6 million of outstanding, floating-rate debt of which $253.6 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause annual interest expense to increase $2.5 million.

During 2003 and 2002, the Company entered into treasury locks to hedge the risk of interest rate movement between the hedge date and the expected pricing date for a portion of certain of the Company's debt offerings during those periods. These swaps terminated and cash-settled resulting in a $5.8 million loss. These swaps were designated as cash flow hedges, and accordingly, the resulting loss will remain in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet and be amortized into earnings as additional interest expense over the life of the related long-term financings.

Foreign Exchange Contracts

The Company's gas marketing subsidiary conducts its business in the United States as well as western Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange rate risk for the Company. To mitigate this risk, the Company enters into forward currency exchange contracts to offset earning volatility from changes in exchange rates between the Canadian and United States dollars. At December 31, 2004 and 2003, the Company had outstanding forward exchange contracts to sell approximately $38.0 million and $0 Canadian dollars, respectively. At December 31, 2004 and 2003, the Company also had outstanding forward exchange contracts to purchase approximately $10.8 million and $3.0 million Canadian dollars, respectively. These contracts had a fair value of $(1.0) million and $0.1 million at December 31, 2004 and 2003, respectively, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2004 settle by April 2005.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. The Company adopted the Black Hills Corporation Credit Policy (BHCCP) that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, the Company has an Executive Credit Committee composed of senior executives that meets on a regular basis to review the Company's credit activities and monitor compliance with the policies adopted by the Company.

For energy marketing, production, and generation activities, the Company mitigates its credit exposure by attempting to conduct its business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and asset security agreements.

The Company performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. The Company maintains a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At the end of the year, the Company's credit exposure (exclusive of retail customers of our regulated utility and communications segment) was concentrated with investment grade companies. Approximately 74 percent of the credit exposure was with investment grade companies. For the 26 percent credit exposure with non-investment grade rated counterparties, approximately 91 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

(3) INVESTMENTS IN ASSOCIATED COMPANIES

Included in Investments on the Consolidated Balance Sheets are the following investments that have been recorded on the equity method of accounting:

- A 12.6 percent, 6.9 percent and 5.3 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., and Project Finance Fund III, L.P., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. The Company has a carrying amount in the investment of $10.3 million and $13.8 million at December 31, 2004 and 2003, respectively, which includes $1.9 million that represents the cost of the investment over the underlying net assets of the funds. As of, and for the year ended December 31, 2004, the funds had assets of $130.5 million, liabilities of $0.3 million and net income of $6.0 million. As of, and for the year ended December 31, 2003, the funds had assets of $163.8 million, liabilities of $0.4 million and net income of $5.0 million.

  Included in "Equity in earnings of unconsolidated subsidiaries" on the 2004, 2003 and 2002 Consolidated Statements of Income is approximately $0.3 million, $3.1 million and $0, respectively, related to the application of the provisions of the AICPA Audit and Accounting Guide, "Audits of Investment Companies," by the funds in which the Company invests. This guidance among other things requires investments held by investment companies to be stated at fair value.

- A 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The Company's carrying amount in the investment is $3.6 million and $3.7 million as of December 31, 2004 and 2003, respectively, which includes $0.6 million that represents the cost of the investment over the value of the underlying net assets of the projects. As of, and for the year ended December 31, 2004, these projects had assets of $19.8 million, liabilities of $12.3 million and net loss of $0.3 million. As of, and for the year ended December 31, 2003, these projects had assets of $23.9 million, liabilities of $16.0 million and net income of $0.8 million.

(4) PROPERTY, PLANT AND EQUIPMENT

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

Regulated

	2004	2003	Lives (in years)
Electric plant:			
Production	$ 320,483	$ 316,544	25-58
Transmission*	83,488	122,640	35-50
Distribution	198,583	150,748	20-40
General	30,658	29,857	7-40
Total electric plant	633,212	619,789	
Less accumulated depreciation and amortization	232,401	212,041	
Electric plant net of accumulated depreciation and amortization	400,811	407,748	
Construction work in progress	4,066	3,060	
Net electric plant	$ 404,877	$ 410,808	

* As part of the Common Use Transmission Open-Access Transmission Tariff FERC filing that was originally made in 2003, the majority of 69KV lines and substation costs were reclassified from Transmission to Distribution assets.

2004

Non-regulated

	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	$ 72,846	$ 36,922	$ 35,924	$ 521	$ 36,445	3-39
Oil & gas	259,695	81,165	178,530	—	178,530	3-40
Energy marketing and transportation	27,517	3,344	24,173	942	25,115	3-40
Power generation	791,275	112,124	679,151	1,110	680,261	3-40
Communications	160,775	56,547	104,228	4,576	108,804	3-31.5
Other	6,633	2,884	3,749	7,951	11,700	5-7
	$1,318,741	$ 292,986	$1,025,755	$ 15,100	$ 1,040,855	

2003

	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	$ 65,932	$ 34,555	$ 31,377	$ 6,353	$ 37,730	3-39
Oil & gas	205,137	65,756	139,381	—	139,381	3-40
Energy marketing and transportation	27,456	2,190	25,266	382	25,648	3-40
Power generation	786,930	81,095	705,835	4,754	710,589	3-40
Communications	159,534	43,930	115,604	—	115,604	3-31.5
Other	3,075	707	2,368	143	2,511	5-7
	$1,248,064	$ 228,233	$1,019,831	$ 11,632	$ 1,031,463	

(5) JOINTLY OWNED FACILITIES

The Company’s subsidiary, Black Hills Power (BHP), 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. BHP 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, 2004, BHP’s investment in the Plant included $73.4 million in electric plant and $34.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. BHP’s share of direct expenses of the Plant was $6.0 million, $5.8 million and $5.5 million for the years ended December 31, 2004, 2003 and 2002, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 21, the Company’s coal mining subsidiary, Wyodak Resources, supplies coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of Wyodak Resources’ coal reserves. Under the coal supply agreement, PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustment for planned outages. Wyodak Resources’ sales to the Plant were $16.2 million, $18.7 million and $19.0 million for the years ended December 31, 2004, 2003 and 2002, respectively.

BHP 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 the Company 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. BHP is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2004, BHP’s share of direct expenses was $0.1 million. As of December 31, 2004, BHP’s investment in the transmission tie was $19.7 million.

The Company, through its subsidiary Black Hills Exploration and Production (BHEP), owns a 44.7 percent non-operating interest in the Newcastle Gas Plant (Gas Plant); a gas processing facility that gathers and processes approximately 3,000 MCF/day of gas, primarily from the Finn-Shurley Field in Wyoming. The Company receives its proportionate share of the Gas Plant’s net revenues and is committed to pay its proportionate share of additions, replacements and operating and maintenance expenses. As of December 31, 2004, the Company’s investment in the Gas Plant included $4.0 million in plant and equipment and $3.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company’s share of revenues of the Gas Plant was $2.5 million, $1.7 million and $1.1million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company’s share of direct expenses for the Gas Plant were $0.3 million, $0.2 million and $0.3 million for the years ended December 31, 2004, 2003 and 2002, respectively. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

(6) VARIABLE INTEREST ENTITY

In January 2003, the FASB issued Interpretation No. 46, “Consolidation of Variable Interest Entities” (FIN 46). In December 2003, the FASB issued FIN No. 46 (Revised) (FIN 46-R) to address certain FIN 46 implementation issues. The Company’s subsidiary, Black Hills Wyoming, has an agreement with Wygen Funding, Limited Partnership, an unrelated variable interest entity (VIE) to lease the Wygen plant. Under the accounting interpretation, as amended, the Company consolidated the VIE effective December 31, 2003. The effect of consolidating the VIE into the Company’s Consolidated Balance Sheet at December 31, 2003 was an increase in total assets of $129.0 million, of which $121.5 million, net of accumulated depreciation of $3.0 million, is included in Property, plant and equipment and an increase in long-term debt in the amount of $128.3 million.

Prior to the December 31, 2003 consolidation, the Company recorded lease expense on the Wygen plant. Lease payments began upon completion of the plant in February 2003. During the twelve month period ended December 31, 2003, lease payments were $2.7 million and are included in Operations and maintenance on the accompanying 2003 Consolidated Statement of Income. The net effect of consolidating the income statement of the VIE on December 31, 2003, was to recognize a cumulative effect charge for $2.5 million (net of $1.4 million of income taxes), which represents the depreciation and interest expense which would have been recorded had the VIE been consolidated at inception. The net effect on current results is to recognize depreciation and interest expense in place of recognizing lease expense. During the twelve month period ended December 31, 2004, depreciation expense was $3.4 million and interest expense was $3.6 million.

(7) LONG-TERM DEBT

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

	2004	2003
Senior unsecured notes at 6.5% due 2013	$ 224,756	$ 249,696
First mortgage bonds:		
8.06% due 2010	30,000	30,000
9.49% due 2018	3,970	4,260
9.35% due 2021	28,305	29,970
8.30% repaid 2004	—	45,000
7.23% due 2032	75,000	75,000
	137,275	184,230
Other long-term debt:		
Pollution control revenue bonds at 6.7% due 2010[a][b]	—	12,300
Pollution control revenue bonds at 4.8% due 2014[b]	6,450	—
Pollution control revenue bonds at 7.5% due 2024[b]	—	12,200
Pollution control revenue bonds at 5.35% due 2024[b]	12,200	—
GECC Financing at 4.01% due 2010[c][d]	28,213	30,214
Other	5,362	6,253
	52,225	60,967
Project financing floating rate debt[d]:		
Fountain Valley project at 4.31% due 2006	82,661	132,328
Valmont and Arapahoe at 3.56% due 2007	124,565	130,632
Wygen project at 2.87% due 2006	111,100	111,100
Wygen project at 2.87% due 2008	17,165	17,165
	335,491	391,225
Total long-term debt	749,747	886,118
Less current maturities	(16,166)	(17,659)
Net long-term debt	$ 733,581	$ 868,459

(a) In September 2004, the Company's electric utility called $5.9 million of pollution control revenue bonds without converting into another form of long-term debt.

(b) In the fourth quarter of 2004, the Company's electric utility called and refinanced $18.7 million of pollution control revenue bonds.

(c) Floating rate debt, 86 percent secured by Gillette combustion turbine and 14 percent secured by a spare LM6000 turbine.

(d) Interest rates are presented as of December 31, 2004.

At December 31, 2004, approximately 31 percent of the Company's $366.6 million variable rate debt balance has been hedged with interest rate swaps moving the floating rates to fixed rates with a weighted average interest rate of 4.22 percent (see Note 2).

Substantially all of the Company's utility 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.

Project financing debt is debt collateralized by a mortgage on each respective project's land and facilities, leases and rights, including rights to receive payments under long-term purchase power contracts. The Fountain Valley, Valmont and Arapahoe project debt is non-recourse debt. The Wygen project debt is additionally guaranteed by the Company (see Note 22).

Certain debt instruments of the Company and its subsidiaries contain restrictions and covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2004. Also, certain of the subsidiaries' debt agreements provide that approximately $17.7 million of the subsidiaries' cash balance at December 31, 2004 may not be distributed to the parent company.

Scheduled maturities of long-term debt for the next five years are: $16.2 million in 2005, $200.4 million in 2006, $115.5 million in 2007, $21.2 million in 2008 and $4.1 million in 2009.

(8) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $350.0 million at December 31, 2004 and $425.0 million at December 31, 2003. At December 31, 2004, these lines consist of a $225.0 million revolving credit facility, which terminates August 20, 2006 and a $125.0 million revolving credit facility that expires on May 12, 2005. The Company had $24.0 million of borrowings and $44.6 million of letters of credit and no borrowings and $54.3 million of letters of credit issued on the lines at December 31, 2004 and 2003, respectively. The Company has no compensating balance requirements associated with these lines of credit.

Interest rates under the facility borrowings vary and are based, at the option of the Company at the time of the loan origination, on either (i) a prime based borrowing rate (5.25 percent at December 31, 2004) or (ii) on a London Interbank Offered Rate (LIBOR) based borrowing rate of LIBOR plus 1.25 percent to LIBOR plus 1.3 percent. The one-month LIBOR rate at December 31, 2004 was 2.4 percent. In addition to interest on outstanding borrowings, the credit facilities contain an annual facility fee of from 0.2 percent to 0.25 percent on the total facility amount, and an annual utilization fee of 0.25 percent.

In addition to the above lines of credit, at December 31, 2004, Enserco Energy (Enserco) has a $150.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The line of credit is secured by all of Enserco's assets and expires on September 30, 2005. The Company has made a $3.0 million guarantee to the lender associated with the line of credit. At December 31, 2004 and 2003, there were outstanding letters of credit issued under the facility of $91.7 million and $80.3 million, respectively, with no borrowing balances on the facility.

Black Hills Energy Resources (BHER) has a $25.0 million uncommitted, discretionary credit facility at December 31, 2004. The facility is secured by cash, accounts receivable and other assets. The transactional line of credit provides credit support for the purchases of crude oil of BHER. The facility allows BHER to elect up to $40.0 million of available credit via notification to the bank at the beginning of each calendar quarter. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2004 and 2003, BHER had letters of credit outstanding of $8.9 million and $7.9 million, respectively, with no borrowing balances on the facility.

The credit facilities and notes payable contain certain restrictive covenants including, among others, the maintenance of a fixed charge coverage ratio, a recourse debt-to-capitalization ratio and a total level of equity. The Company and its subsidiaries had complied with all the covenants at December 31, 2004. These facilities do not contain default provisions pertaining to credit rating status.

The Company has entered into floating-to-fixed interest rate swaps to hedge a portion of its exposure to interest rate fluctuations with the above floating rate obligations. See Note 2 for further details.

(9) ASSET RETIREMENT OBLIGATIONS

SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143) provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was effective January 1, 2003. SFAS 143 requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. The Company has identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in our Oil and Gas segment and reclamation of our coal mining sites in our Coal mining segment. Cumulative accretion and accumulated depreciation has been recognized for the time period from the date the liability would have been recognized had the provisions of SFAS 143 been in effect, to the date of its adoption. Upon adoption, the Company recorded a $2.9 million transition adjustment to properly reflect its asset retirement obligations in accordance with the provisions of SFAS 143. The transition adjustment represents the current estimated fair value of the Company's obligation to plug its oil and gas wells at the time of abandonment and an adjustment to its liability for reclaiming its coal mining sites following completion of mining activity.

The cumulative effect on earnings of adopting SFAS 143 was a benefit of approximately $0.2 million representing the cumulative amounts of depreciation and changes in the asset retirement obligation due to the passage of time for historical accounting periods. The cumulative effect of initially applying SFAS 143 was recognized as a change in accounting principle.

The following table presents the details of the Company's asset retirement obligations which are included on the accompanying Consolidated Balance Sheets in "Other" under "Deferred credits and other liabilities" (in thousands):

	Balance at 12/31/03	Liabilities Incurred	Liabilities Settled	Accretion	Cash Flow Revisions	Balance at 12/31/04
Oil and Gas	$ 7,233	$ 157	$ —	$ 552	$ —	$ 7,942
Mining	15,752	549	(1,102)	668	—	15,867
Total	$ 22,985	$ 706	$ (1,102)	$ 1,220	$ —	$ 23,809

(10) COMMON STOCK

During 2003, the Company completed a public offering of its common stock through which 4.6 million shares were sold at $27 per share. Net proceeds were approximately $118 million after commissions and expenses. The proceeds were used to pay off a $50 million credit facility and to repay $68 million under the Company's 364-day revolving credit facility, which expired on August 26, 2003. In addition, in 2003 the Company issued 481,509 shares and 45,000 warrants to purchase common stock in the acquisition of Mallon Resources Corporation (see Note 24).

Equity Compensation Plans

The Company has several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options, performance shares, and an employee stock purchase plan (ESPP). The Company accounts for such plans under APB No. 25, and has adopted the disclosure-only provisions of SFAS 123. For a discussion of the effect on earnings and earnings per common share for the years ended December 31, 2004, 2003 and 2002, if the Company had applied SFAS 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant (see Note 1).

The Company has granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The Company has 318,330 shares available to grant at December 31, 2004. The options granted vest one-third each year for three years and expire after ten years from the grant date.

A summary of the status of the stock option plans at December 31, 2004, 2003 and 2002, and changes during the years then ended are as follows:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,211,122	$27.66	1,042,989	$27.68	992,872	$ 26.55
Granted	203,000	29.81	289,665	28.01	211,985	30.04
Forfeited	(53,154)	31.54	(66,153)	34.31	(34,838)	33.52
Exercised	(71,099)	22.12	(55,379)	22.00	(127,030)	21.20
Balance at end of year	1,289,869	$28.14	1,211,122	$27.66	1,042,989	$ 27.68
Exercisable at end of year	885,894	$27.68	747,482	$26.45	566,654	$ 25.36

Details of outstanding options at December 31, 2004 are as follows:

Option Exercise Prices	Shares Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares Exercisable	Weighted Average Exercise Price
$16.67 to $22.00	324,520	$ 21.57	4.8 years	324,520	$ 21.57
$22.01 to $27.00	204,005	$ 24.32	6.0 years	174,656	$ 24.18
$27.01 to $32.00	544,669	$ 29.14	8.5 years	200,336	$ 29.36
$32.01 to $37.00	109,175	$ 34.42	7.3 years	79,482	$ 34.39
$37.01 to $38.68	70,500	$ 37.74	6.0 years	69,900	$ 37.74
$55.36	37,000	$ 55.36	6.4 years	37,000	$ 55.36

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2004	2003	2002
Weighted average fair value of options at grant date	$ 6.90	$ 2.74	$ 6.63
Weighted average risk-free interest rate	3.82%	3.09%	4.17%
Weighted average expected price volatility	43.52%	46.80%	39.09%
Weighted average expected dividend yield	4.16%	4.28%	3.86%
Expected life in years	7	7	7

The Company maintains the ESPP under which it sells shares to employees at 90 percent of the stock's market price on the offering date. The Company issued 15,644, 24,963 and 17,496 shares of common stock under the ESPP in 2004, 2003 and 2002, respectively. At December 31, 2004, 119,705 shares are reserved and available for issuance under the ESPP.

During 2003 and 2001, the Company issued a total of 12,575 common shares and 36,550 common shares, respectively, as a stock bonus award to its non-officer employees. The bonuses were grossed up to cover related employee taxes. The total pre-tax compensation charge recognized by the Company was $0.3 million and $0.4 million in 2003 and 2002, which was based on the market value of the stock on the grant date.

The Company issued 16,019 and 45,123 restricted stock units in 2004 and 2003, respectively, and 34,828, 24,643 and 26,047 restricted common shares, to certain officers in 2004, 2003 and 2002, respectively. The shares carry a restriction on the officer's ability to sell the shares until the shares vest. The shares substantially vest one-third per year over three years, contingent on continued employment. Compensation cost related to the awards is recognized over the vesting period. The Company recognized pre-tax compensation cost related to the awards of $1.7 million in 2004, $0.9 million in 2003 and $0.4 million in 2002. During 2003, the Company also issued 11,215 shares of common stock for the conversion of restricted stock units.

On March 1, 2004, certain officers of the Company and its subsidiaries were named participants in a performance share award plan. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. In addition, the Company's stock price must also increase during the performance periods. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Total Target Grant of Shares
March 1, 2004	March 1, 2004-December 31, 2005	15,458
March 1, 2004	March 1, 2004-December 31, 2006	31,384

Participants may earn additional performance shares if the Company's total shareholder return exceeds the 50th percentile of the selected peer group. The final value of the performance shares may vary according to the number of shares of common stock that are ultimately granted based upon the performance criteria. Compensation expense recognized for the performance share awards for the year ended December 31, 2004 was $0.5 million. The performance awards are paid in 50 percent cash and 50 percent common stock.

The Company issued 10,310, 3,075 and 38,749 shares of common stock in 2004, 2003 and 2002, respectively to certain key employees under the Short-term Annual Incentive Plan. The weighted average grant date fair value of the stock awards was $31.10, $23.10, and $28.60, respectively.

Dividend Reinvestment and Stock Purchase Plan

The Company has a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100 percent of the recent average market price. The Company has the option of issuing new shares or purchasing the shares on the open market. The Company issued 22,934 new shares at a weighted average price of $30.41 and 71,727 open market shares at a weighted average price of $29.45 in 2004; 94,346 new shares in 2003 at a weighted average price of $28.90; and 66,882 new shares in 2002 at a weighted average price of $28.65. At December 31, 2004, 249,339 shares of unissued common stock were available for future offering under the Plan.

Dividend Restrictions

Some of the Company's credit facilities contain restrictions on the payment of cash dividends under a circumstance of default or event default. An event of default would be deemed to have occurred if the Company did not meet the financial covenant requirements for the respective facility. The most restrictive financial covenants include the following: fixed charge coverage ratio of not less than 1.5 to 1.0; a recourse leverage ratio not to exceed 0.65 to 1.00; and a minimum consolidated net worth of $550 million plus 50 percent of our aggregate consolidated net income since April 1, 2004. As of December 31, 2004, we were in compliance with the above covenants. In addition, under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. As part of the order approving our public utility holding company, we agreed that the consolidated company and the utility subsidiaries will maintain at least a 30 percent common equity ratio. Through December 31, 2007, our non-utility subsidiaries are also allowed to pay dividends out of capital and unearned surplus if (i) they have received excess cash as a result of the sale of assets, (ii) they have engaged in a restructuring or reorganization and/or (iii) they are returning capital to an associate company.

Treasury Shares Acquired

The Company acquired 4,005 and 4,400 shares of treasury stock related to a forfeiture of unvested restricted stock in 2004 and 2003, respectively, and 7,508, 3,119 and 696 shares related to the share withholding provisions of the restricted stock plan for the payment of taxes associated with the vesting of restricted shares in 2004, 2003 and 2002, respectively.

(11) PREFERRED STOCK

The Company has 25,000,000 authorized shares of no-par preferred stock of which 21,500 shares have been designated as the No Par Preferred Stock, Series 2000-A. As of December 31, 2004, 7,771 shares of the Series 2000-A has been issued, of which 6,839 shares were outstanding. During 2004, 932 shares of the Series 2000-A Preferred Stock were converted into 26,628 shares of common stock at the conversion price of $35.00 per share.

The Company did not issue any preferred shares in 2004 or 2002, but issued 2,594 shares in 2003 in accordance with the Indeck Capital acquisition "earn-out" provisions (see Note 21). The preferred shares issued are non-voting, cumulative, no par shares with a dividend rate equal to 1 percent per annum per share, computed on the basis of $1,000 per share plus an amount equal to any dividend declared payable with respect to the common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. The record and payment dates are the same as the record and payment dates with respect to the payment of dividends on common stock. No dividend may be declared or paid with respect to common stock unless such a dividend is declared and paid with respect to the preferred stock. The preferred stock is senior to the common stock in liquidation events.

The Company may redeem the preferred stock in whole or in part, at any time solely at its option. The redemption price per share for the preferred stock is $1,000 per share plus all accrued and unpaid dividends. Each share of the preferred stock is convertible at the option of the holder into common stock at any time prior to July 7, 2005 and is automatically converted into common stock on July 7, 2005. Each share of preferred stock is convertible into 28.57 common shares. If the Company delivers a notice of redemption, the conversion price is adjusted equal to the lesser of (i) the conversion price then in effect, and (ii) the current market price on the redemption notice date.

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 64,506	$ 64,506	$ 172,759	$ 172,759
Restricted cash	$ 3,069	$ 3,069	$ 1,350	$ 1,350
Derivative financial instruments – assets	$ 47,977	$ 47,977	$ 26,804	$ 26,804
Derivative financial instruments – liabilities	$ 43,206	$ 43,206	$ 32,967	$ 32,967
Notes payable	$ 24,000	$ 24,000	$ —	$ —
Long-term debt, including current maturities	$ 749,747	$ 788,212	$ 886,118	$ 924,879

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 and Restricted Cash

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 various instruments the Company uses and the valuation method employed are available in Note 2.

Notes Payable

The carrying amount approximates fair value due to their variable interest rates with short reset periods.

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 bonds.

(13) CONTRACT TERMINATION REVENUE

During the third quarter of 2003, the Company completed a transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, a subsidiary of Allegheny Energy, Inc., for capacity and energy at the Company's Las Vegas II power plant. The Company received a cash payment of $114.0 million, which is recorded as "Contract termination revenue" in the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment.

(14) IMPAIRMENT OF LONG-LIVED ASSETS

As a result of the contract termination discussed in Note 13, the Company assessed the recoverability of the carrying value of the Las Vegas II facility. The carrying value of the assets tested for impairment was $237.2 million. This assessment resulted in an impairment charge of $117.2 million to write down the related Property, plant and equipment by $83.1 million, net of accumulated depreciation of $5.1 million, and intangible assets by $34.1 million, net of accumulated amortization of $1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. This charge is included as a component of "Operating expenses" on the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment. In addition to the above asset impairment, certain long-lived assets accounted for as discontinued operations have incurred impairment charges (see Note 19).

(15) GAIN ON SALE OF ASSETS

On March 1, 2004, the Company's subsidiary, Daksoft, Inc., sold assets used in its campground reservation system. The Company recorded a pre-tax gain on the sale of the assets of $1.0 million, which is included as an offset to Operating expenses, Administrative and general on the accompanying Consolidated Statement of Income. Prior to this sale, for segment reporting (see Note 23) results of operations for Daksoft were included in the Communications segment. As Daksoft now primarily provides information technology support to the Company, its results are included in "Corporate" for segment reporting.

(16) OPERATING LEASES

The Company has entered into lease agreements relating to certain power plant land leases, office facility leases and storage agreements.

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2005	$ 2,745
2006	1,552
2007	1,379
2008	1,400
2009	1,255
Thereafter	10,874
	$ 19,205

(17) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years indicated was:

	2004	2003 (in thousands)	2002
Current:			
Federal	$ 223	$ 35,414	$ (3,786)
State	(2,705)	5,235	(1,494)
	(2,482)	40,649	(5,280)
Deferred:			
Federal	30,580	(6,625)	30,128
State	(1,115)	(4,105)	2,212
Tax credit amortization	(279)	(318)	(416)
	$ 26,704	$ 29,601	$ 26,644

The temporary differences, which gave rise to the net deferred tax liability, were as follows:

Years ended December 31,	2004	2003
	(in thousands)	
Deferred tax assets, current:		
Valuation reserves	$ 2,235	$ 2,824
Mining development and oil exploration	377	980
Employee benefits	7,799	6,216
Items of other comprehensive income	1,680	2,375
Other	250	1,586
	12,341	13,981
Deferred tax liabilities, current:		
Prepaid expenses	2,156	1,733
Derivative fair value adjustments	188	850
Employee benefits	3,608	4,397
Items of other comprehensive income	618	160
Other	1,534	2,585
	8,104	9,725
Net deferred tax asset, current	$ 4,237	$ 4,256
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 873	$ 102
Mining development and oil exploration	205	213
Employee benefits	817	—
Regulatory asset	1,387	1,616
Deferred revenue	931	1,148
Items of other comprehensive income	1,149	2,147
Net operating loss (net of valuation allowance)	4,863	4,927
Asset impairment	40,061	41,023
Other	8,867	12,436
	59,153	63,612
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	165,340	135,614
Regulatory liability	4,172	4,320
Mining development and oil exploration	34,126	20,445
Derivative fair value adjustments	110	614
Items of other comprehensive income	115	—
Other	14,913	27,659
	218,776	188,652
Net deferred tax liability, non-current	$ 159,623	$ 125,040
Net deferred tax liability	$ 155,386	$ 120,784

The following table reconciles the change in the net deferred income tax liability from December 31, 2003, to December 31, 2004, to deferred income tax expense:

	2004 (in thousands)
Net change in deferred income tax liability from the preceding table	$ 34,602
Deferred taxes associated with 2003 Federal Income Tax Return True-up primarily related to prepaid expenses and plant-related differences	(3,442)
Deferred taxes associated with other comprehensive loss	(2,266)
Deferred taxes related to net operating loss acquisitions	407
Other	(115)
Deferred income tax expense for the period	$ 29,186

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

	2004	2003	2002
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	(3.2)	0.8	0.5
Amortization of excess deferred and investment tax credits	(0.5)	(0.5)	(0.6)
Percentage depletion in excess of cost	(0.8)	(0.9)	(0.7)
Research and development credit	—	(0.6)	(1.5)
Other	1.3	0.6	(1.3)
	31.8%	34.4%	31.4%

At December 31, 2004, the Company had the following net operating loss carryforwards which were acquired as part of the Mallon acquisition (in thousands):

Net Operating Loss Carryforward	Expiration Year
$ 101	2009
336	2010
361	2011
48	2012
463	2013
22,789	2014-2023

As of December 31, 2004, the Company had a valuation allowance of $19.2 million against these NOL carryforwards. Ultimate usage of these NOLs depends upon the Company’s future tax planning and filings. If the valuation allowance is reduced due to higher than anticipated utilization of the NOLs, the offsetting amount would reduce the Company’s financial reporting basis in its Mallon property.

(18) OTHER COMPREHENSIVE INCOME (LOSS)

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

	2004		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 91	$ (32)	$ 59
Net change in fair value of derivatives designated as cash flow hedges	5,690	(2,234)	3,456
Other comprehensive income (loss)	$ 5,781	$ (2,266)	$ 3,515

	2003		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 10,293	$ (3,603)	$ 6,690
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $(331))	(592)	44	(548)
Reclassification adjustment for interest rate swaps designated as cash flow hedges settled as part of the hydroelectric asset sale and included in net income (net of minority interest share of ($2,379))	6,361	(2,433)	3,928
Other comprehensive income (loss)	$ 16,062	$ (5,992)	$ 10,070

	2002		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (13,556)	$ 4,745	$ (8,811)
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $(164))	(13,342)	4,703	(8,639)
Other comprehensive income (loss)	$ (26,898)	$ 9,448	$ (17,450)

(19) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of Statement of Financial Accounting Standards No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” (SFAS 144). Accordingly, results of operations and the related charges for discontinued operations have been classified as “Income from discontinued operations, net of tax” in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as “Assets of discontinued operations” and “Liabilities of discontinued operations.” For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of Landrica Development Corp.

On May 21, 2004, the Company sold its subsidiary, Landrica Development Corp. Landrica’s primary assets consisted of a coal enhancement plant and land. The purchaser made a $0.5 million cash payment to the Company and assumed a $2.9 million reclamation liability. The sale resulted in a $2.1 million after-tax gain. For segment reporting purposes, Landrica was previously included in the Coal Mining segment.

Net income from the discontinued operations at December 31, is as follows (in thousands):

	2004	2003	2002
Pre-tax (loss) income from discontinued operations	$ (40)	$ 833	$ 704
Pre-tax gain on disposal	3,208	—	—
Income tax expense	(1,120)	(319)	(263)
Net income from discontinued operations	$ 2,048	$ 514	$ 441

Assets and liabilities of the discontinued operations are as follows (in thousands):

	December 31 2003
Current assets	$ 31
Property, plant and equipment	151
Investments	500
Non-current assets	—
Other current liabilities	(118)
Deferred reclamation	(2,858)
Other non-current liabilities	(1)
Net liabilities of discontinued operations	$ (2,295)

Adoption of Plan to Sell Pepperell Plant

During the third quarter of 2003, the Company adopted a plan to sell the 40 megawatt gas-fired Pepperell plant, which is part of the Power generation segment. The Pepperell plant is the Company's only remaining generation asset in the Eastern market and management has determined that it is a non-strategic asset. In connection with the plan to sell, the Company determined that the carrying value of the underlying assets exceeded their fair value and a charge to operations was required. Consequently, in the third quarter of 2003, the Company recorded an after-tax charge of approximately $0.6 million.

The Company's original plan of sale included an expectation that the Pepperell plant would be sold by September 2004. While various market circumstances prevented a sale by this time, the Company continues to actively market the plant, taking actions necessary to respond to market changes. Consequently, in the fourth quarter of 2004, the Company recorded an additional after-tax charge of approximately $0.7 million, which represents the difference between the carrying value of the assets versus the estimated fair value, less cost to sell.

For business segment reporting purposes, the Pepperell plant results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations during the years ended December 31, are as follows:

	2004	2003	2002
		(in thousands)	
Operating revenues	$ 120	$ 2,152	$ 3,572
Pre-tax income (loss) from discontinued operations	$ (972)	$ (1,422)	$ (1,115)
Pre-tax loss on disposal	(1,064)	(3,464)	—
Income tax benefit	712	2,979	397
Net loss from discontinued operations	$ (1,324)	$ (1,907)	$ (718)

Assets and liabilities of the discontinued operations at December 31, are as follows:

	2004	2003
	(in thousands)	
Current assets	$ 107	$ 249
Property, plant and equipment	—	1,064
Non-current deferred tax asset	2,952	2,580
Other current liabilities	(167)	(86)
Non-current deferred tax liability	(484)	(381)
Net assets of discontinued operations	$ 2,408	$ 3,426

Sale of Hydroelectric Assets

On September 30, 2003 the Company sold its seven hydroelectric power plants located in Upstate New York. The aggregate cash purchase price of approximately $186 million was used in part to pay off the remaining amount of project-level debt and related interest rate swaps associated with these assets, which totaled approximately $91 million. The purchasers are affiliates of Boralex, Inc., a Canadian corporation, and Boralex Power Income Fund, an unincorporated Canadian trust of which Boralex owns an interest (collectively the Purchaser). The agreements with the Purchaser required that the Company deliver 100 percent of the equity interests of the entities that owned the facilities and required that the Company acquire those minority interests which it did not then own, in advance of closing. In anticipation of entering into the agreements with the Purchaser, on July 8, 2003, the Company acquired the equity interests of a third party investor for $9.0 million and entered into a definitive agreement to acquire the balance of the equity interests from another third party investor. For business segment reporting purposes, the hydroelectric power plants results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations at December 31, are as follows:

	2003	2002
	(in thousands)	
Operating revenues	$ 21,800	$ 27,397
Pre-tax income from discontinued operations	$ 7,986	$ 8,484
Pre-tax gain on disposal	13,864	—
Income tax expense	(11,355)	(3,152)
Net income from discontinued operations	$ 10,495	$ 5,332

Sale of Coal Marketing Subsidiary

During the second quarter of 2002, the Company adopted a plan to dispose of its coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. In connection with the plan of disposal, the Company determined that the carrying values of some of the underlying assets exceeded their fair values and a charge to operations was required.

Consequently, in the second quarter of 2002, the Company recorded an after-tax charge of approximately $1.0 million, which represents the difference between the carrying values of the assets and liabilities of the subsidiary versus their fair values, less cost to sell. In addition, during the first quarter of 2002, the Company had a $0.8 million (pre-tax) impairment loss of certain intangibles as a result of a weak coal market. For business segment reporting purposes, the coal marketing business results were previously included in the Energy marketing and transportation segment.

Gross margins on energy trading contracts and net income from the discontinued operation at December 31, are as follows:

	2003	2002
	(in thousands)	
Gross margins on energy trading contracts	$ —	$ 235
Pre-tax loss from discontinued operations	$ —	$ (2,679)
Pre-tax loss on disposal	—	(1,588)
Income tax benefit	834	1,630
Net income (loss) from discontinued operations	$ 834	$ (2,637)

(20) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company and those of the following subsidiaries, Black Hills Power, Wyodak Resources Development Corp., Black Hills Exploration and Production and Daksoft 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 securities and cash equivalents. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2004	2003
	(in thousands)	
Projected benefit obligation at beginning of year	$ 61,879	$ 50,888
Service cost	1,772	1,293
Interest cost	3,637	3,351
Actuarial (gain) loss	(237)	2,199
Discount rate change	—	6,414
Benefits paid	(2,291)	(2,221)
Taxable wage rate and cost of living rate change	—	(45)
Net increase	2,881	10,991
Projected benefit obligation at end of year	$ 64,760	$ 61,879

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

	2004	2003
	(in thousands)	
Beginning market value of plan assets	$ 48,797	$ 32,437
Benefits paid	(2,291)	(2,221)
Investment income	6,276	8,081
Employer contributions	—	10,500
Ending market value of plan assets	$ 52,782	$ 48,797

Funding information for the Plan is as follows:

	2004	2003
	(in thousands)	
Fair value of plan assets	$ 52,782	$ 48,797
Projected benefit obligation	(64,760)	(61,879)
Funded status	(11,978)	(13,082)
Unrecognized:		
Net loss	20,674	24,170
Prior service cost	1,377	1,609
Net asset recognized	$ 10,073	$ 12,697

Amounts recognized in statement of financial position consist of:

	2004	2003
	(in thousands)	
Net pension asset	$ 10,073	$ 12,697
Accumulated benefit obligation	$ 51,690	$ 48,581

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $10.1 million and $12.7 million at December 31, 2004 and 2003, respectively, which is included in the line item Other Assets on the accompanying Consolidated Balance Sheets.

Components of Net Periodic Pension Expense

	2004	2003	2002
		(in thousands)	
Service cost	$ 1,772	$ 1,293	$ 979
Interest cost	3,637	3,351	3,135
Expected return on assets	(4,515)	(3,119)	(4,206)
Amortization of prior service cost	232	232	231
Recognized net actuarial (gain) loss	1,498	1,407	102
Net pension (income) expense	$ 2,624	$ 3,164	$ 241

Additional Information

	2004	2003
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ —	$12,474

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2004	2003
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	4.39%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%
Expected long-term rate of return on assets*	9.50%	10.00%	10.50%
Rate of increase in compensation levels	4.39%	5.00%	5.00%

*The expected rate of return on plan assets was changed from 9.5 percent in 2004 to 9.0 percent for the calculation of the 2005 net periodic pension cost. This change is expected to increase pension costs in 2005 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 10.0 percent and 10.5 percent for the 2004 and 2003 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, 2004, 13.2 percent, 13.7 percent, 10.4 percent and 10.9 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 intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. 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:

	2004	2003
Domestic equity	59.7%	44.8%
Foreign equity	34.5	26.6
Fixed income	2.6	3.8
Cash	3.2	24.8[(a)]
Total	100.0%	100.0%

(a) Allocation includes $10.5 million cash contribution made to the plan on September 30, 2003.

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 includes the investment objective that the achieved long-term rate 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 regard 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 2005.

Estimated Future Benefit Payments

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

2005	$ 2,496
2006	2,519
2007	2,582
2008	2,689
2009	2,855
2010-2014	17,351

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for outside directors and 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

	2004	2003
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 16,194	$ 11,303
Service cost	536	425
Interest cost	965	759
Actuarial (gains) losses	(582)	6,107
Benefits paid	(133)	(120)
Discount rate change	—	2,256
Taxable wage rate and cost of living rate change	—	107
Change in salary projection	—	(4,643)
Net increase	786	4,891
Projected benefit obligation at end of year	$ 16,980	$ 16,194
Fair value of plan assets at end of year	$ —	$ —
Funded status	(16,980)	(16,194)
Unrecognized net loss	9,249	10,577
Unrecognized prior service cost	53	62
Contributions	84	30
Net amount recognized	$ (7,594)	$ (5,525)

	2004	2003
	(in thousands)	
Amounts recognized in consolidated balance sheets consist of:		
Net pension (liability)	$ (10,902)	$ (8,886)
Intangible asset	52	68
Contributions	84	30
Accumulated other comprehensive loss	3,172	3,263
Net amount recognized	$ (7,594)	$ (5,525)
Accumulated benefit obligation	$ 10,902	$ 8,886

The provisions of SFAS 87 required the Company to record a net pension liability of $10.9 million and $8.9 million at December 31, 2004 and 2003, respectively. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets.

Components of Net Periodic Benefit Cost

	2004	2003	2002
		(in thousands)	
Service cost	$ 536	$ 425	$ 240
Interest cost	965	759	432
Amortization of prior service cost	9	(2)	26
Recognized net actuarial loss	748	511	145
Net periodic benefit cost	$ 2,258	$ 1,693	$ 843

Additional Information

	2004	2003
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ 91	$ (2,181)

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2004	2003
Discount rate	6.00%	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	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%
Rate of increase in compensation levels	5.00%	5.00%	5.00%

Plan Assets

The plans have no assets. The Company funds on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.3 million in 2005.

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

Fiscal Year Ending	
2005	$ 316
2006	307
2007	308
2008	318
2009	296
2010-2014	1,361

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.

These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plan.

Obligation and Funded Status

	2004	2003
	(in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of year	$ 11,151	$ 8,647
Service cost	561	383
Interest cost	662	576
Plan participant's contributions	385	381
Benefits paid and actual expenses	(611)	(606)
Actuarial (gains) losses	(1,156)	1,770
Net (decrease) increase	(159)	2,504
Accumulated postretirement benefit obligation at end of year	$ 10,992	$ 11,151
Fair value of plan assets at end of year	$ —	$ —
Funded status	(10,992)	(11,151)
Unrecognized net loss	2,538	3,882
Unrecognized prior service cost	(288)	(311)
Unrecognized transition obligation	1,198	1,348
Contributions	36	60
Net amount recognized	$ (7,508)	$ (6,172)

Amounts recognized on the accompanying Consolidated Balance Sheets consist of:

	2004	2003
	(in thousands)	
Accrued postretirement liability	$ (7,508)	$ (6,172)

Components of Net Periodic Benefit Cost

	2004	2003 (in thousands)	2002
Service cost	$ 561	$ 383	$ 284
Interest cost	662	576	519
Amortization of transition obligation	150	150	150
Amortization of prior service cost	(24)	(24)	(24)
Recognized net actuarial loss	189	89	35
Net periodic benefit cost	$ 1,538	$ 1,174	$ 964

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30

	2004	2003
Discount rate	6.00%	6.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year

	2004	2003	2002
Discount rate	6.00%	6.75%	7.50%

The healthcare trend rate assumption for 2003 fiscal year disclosure and 2004 fiscal year expense and disclosure is 12 percent for fiscal 2004 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 2003 fiscal year expense was 11 percent for fiscal 2003 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2009.

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 $0.3 million or 24 percent and the accumulated periodic postretirement benefit obligation $2.2 million or 20 percent. A 1 percent decrease would reduce the service and interest cost by $0.2 million or 18 percent and the accumulated periodic postretirement benefit obligation $1.7 million or 16 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 2005.

Estimated Future Benefit Payments

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

Fiscal Year Ending	
2005	$ 238
2006	277
2007	306
2008	337
2009	390
2010-2014	2,759

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 of 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 $1.4 million for 2004, $1.4 million for 2003 and $1.3 million for 2002.

(21) COMMITMENTS AND CONTINGENCIES

Variable Interest Entity

The Company’s subsidiary, Black Hills Wyoming, has an Agreement for Lease and Lease with Wygen Funding, Limited Partnership (the variable interest entity) for the Wygen plant. The Company is considered the “primary beneficiary” and therefore the variable interest entity has been consolidated by the Company into the accompanying consolidated financial statements (See Note 6). The initial term of the lease is five years, with two five-year renewal options, and includes a purchase option equal to the adjusted acquisition cost. The adjusted acquisition cost is essentially equal to the cost of the plant. At the end of each lease term, the Company may renew the lease, purchase the plant, or sell the plant on behalf of the variable interest entity, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the investors, the Company will be required to make a payment to the variable interest entity of the shortfall up to 83.5 percent of the adjusted acquisition cost, or approximately $111.1 million. The Company has guaranteed the obligations of Black Hills Wyoming to the variable interest entity. As discussed in Note 6, the Company has recorded the debt of the Variable Interest Entity on the Consolidated Balance Sheet, which was $128.3 million at December 31, 2004.

Acquisition Earn-out Agreement

On July 7, 2000, the Company acquired Indeck Capital, Inc. and merged it into its subsidiary, Black Hills Generation (f/k/a Black Hills Energy Capital, Inc.). The acquisition was a stock transaction with the Company issuing 1,536,747 shares of common stock to the shareholders of Indeck priced at $21.98 per share, along with $4.0 million in preferred stock, resulting in a purchase price of $37.8 million. Additional consideration, consisting of common and preferred stock, was payable in the form of an earn-out over a four-year period beginning in 2000. As of December 31, 2004, earn-out consideration valued at $13.7 million for book purposes has been recorded. Litigation concerning the earn-out is described in “Legal Proceedings” within this note. Additional consideration paid out under the earn-out is recorded as an increase to goodwill. The earn-out consideration is based on the acquired company’s earnings during such period and cannot exceed $35.0 million in total.

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 $10.0 million in 2004, $10.8 million in 2003 and $10.9 million (net of a $1.3 million refund for prior years) in 2002.

In addition, the Company has a firm network transmission agreement for 36 MWs 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 2004, $0.5 million in 2003 and $0.7 million in 2002.

Long-Term Power Sales Agreements

The Company, through its subsidiaries, has the following significant long-term power sales contracts:

- The Company has long-term power sales contracts with Public Service Company of Colorado (PSCO) for the output of several of its plants. All of the output of the Company's Fountain Valley, Arapahoe and Valmont gas-fired facilities, totaling 450 megawatts, is included under the contracts which expire in 2012. The contracts are treated as leases under accounting principles generally accepted in the United States and establish capacity and availability payments over the lives of the contracts. The contracts are tolling arrangements in which the Company assumes no fuel price risk.

- The Company has a ten-year power sales contract with Cheyenne Light, Fuel and Power (CLF&P) for the output of the 40 megawatt gas-fired Gillette CT. The Company assumes fuel price risk under this agreement since the fuel price is fixed at the outset of each month and CLF&P has the right to dispatch the facility on a day-ahead basis. The Company is permitted to remarket the energy that is not prescheduled by CLF&P. This agreement has been temporarily assigned from CLF&P to its former affiliate, PSCO, for the four-year term of CLF&P's all requirements power purchase agreement with PSCO, which expires December 31, 2007. The Company acquired CLF&P on January 21, 2005 (see Note 25).

- The Company has a ten-year contract with CLF&P for 60 megawatts of contingent capacity from the 90 megawatt Wygen plant. The Company has consented, subject to receipt of lender approval, to CLF&P's assignment of this agreement to its affiliate, PSCO, for the term of its all requirements power purchase agreement, which expires December 31, 2007. Twenty megawatts of the remaining capacity of this plant has been sold under a ten year unit contingent contract with the Municipal Energy Agency of Nebraska (MEAN).

- The Company has a ten-year power sales contract with the MEAN for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant. The contract commenced in February, 2003.

- The Company has a long-term contract for the output of the 53 megawatt Las Vegas I plant with Nevada Power Company (NPC) through 2024.

- The Company has a long-term contract to provide capacity and energy from the Las Vegas II plant to NPC. The contract became effective April 1, 2004 and expires December 31, 2013. The contract is a tolling arrangement whereby NPC is responsible for supplying natural gas. The Las Vegas II power plant, comprised of combined-cycle gas turbines, is rated at 224 megawatts. The power plant's capacity and energy will be fully dispatchable by NPC to serve its retail load.

- The Company has entered into a tolling agreement with Southern California Edison for all of the capacity and energy from the Company's gas-fired Harbor Cogeneration plant. The agreement commences April 1, 2005 and expires May 31, 2008. Through October 2004, the facility sold capacity and energy under a seasonal agreement that ran from June through October of each year.

- 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 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. Both contracts are served by BHP and are integrated into its control area and are treated as part of the utility's firm native load.

Transmission Services Agreement

The Company has a Firm Point-To-Point Transmission Service Agreement (TSA) with NPC related to the Las Vegas II power plant that expires April 30, 2008. The TSA provided transmission service in support of a Capacity and Ancillary Services Sale and Tolling Services Agreement with Allegheny Energy Supply Company, LLC (Allegheny), which was terminated in September 2003. On April 1, 2004, the Company's new long-term tolling contract to provide capacity and energy from the Las Vegas II plant to NPC became effective. The Las Vegas II plant is interconnected with NPC's transmission system through a step-up transformer owned by Las Vegas Cogeneration II, LLC, pursuant to an interconnection agreement on file with FERC. To the extent that transmission rights established under the TSA cannot be remarketed, costs under the agreement may not be recoverable. Payments under the TSA are approximately $3.9 million per year based on current tariffs. In its consideration and approval of the NPC tolling contract, the Nevada Public Utilities Commission established a linkage between the TSA and the tolling contract that results in the Company recognizing the costs of the TSA over the term of the tolling contract (10 years, $1.6 million per year) rather than the remaining term of the TSA (3.5 years, $3.9 million per year).

Reclamation Liability

Under its mining permit, Wyodak Resources is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land with an equivalent amount added to the asset costs. The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. Approximately $0.7 million and $0.6 million was charged to accretion expense for the years ended December 31, 2004 and 2003, respectively. Approximately $0.5 million and $0.3 million was charged to depreciation expense for the years ended December 31, 2004 and 2003. Approximately $0.9 million was charged to operations as reclamation expense in 2002. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $15.9 million and $15.8 million at December 31, 2004 and 2003, respectively.

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's electric utility, BHP, broke, and electrical arcing from the severed line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National Forest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against BHP, 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 BHP 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. The Company continues to investigate the cause and origin of the fire, and the damage claims. A trial date has been set for early 2005. 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 BHP.

On September 6, 2002, the State of South Dakota commenced litigation against BHP, 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 BHP, 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.

BHP is completing its own investigation of the fire cause and origin. BHP’s investigation is continuing, but based upon information currently available, BHP 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. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through September 2004, various private civil actions were filed against BHP, 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.

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 BHP. 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 BHP 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. BHP 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 and will vigorously defend this matter, the timing and outcome of which is uncertain.

Price Reporting Class Actions

A. Cornerstone Propane Partners, L.P.

On August 18, 2003, Cornerstone Propane Partners, L.P. commenced a putative class action lawsuit against over thirty energy companies. *Cornerstone Propane Partners, L.P. v. Reliant Energy Services, Inc., et. al., Civ. No. 03-CV-6168 (U.S. District Court, Southern District of New York)("Cornerstone Propane Litigation").* The Complaint, which names Black Hills Corporation and Enserco Energy Inc. as defendants, asserts claims for an unspecified amount of damages, based upon alleged violations of the Commodity Exchange Act. General allegations in the Complaint assert that defendants manipulated natural gas futures contracts through false reporting of prices and volumes. Similar specific allegations are made against Black Hills Corporation and Enserco, based upon claims that former traders at Enserco reported false price and volume information to trade publications. Other defendants are alleged to have manipulated spot market gas prices by engaging in "wash trades" and/or by "churning" natural gas trades. Initially, the plaintiff seeks an order certifying the proceeding as a class action according to applicable rules.

B. Roberto E. Calle Gracey

On October 1, 2003, Roberto E. Calle Gracey commenced a putative class action lawsuit against a group of defendants that sets forth claims and demands similar to those described above with respect to the *Cornerstone Propane Litigation*. Black Hills Corporation and Enserco Energy, Inc. are named as defendants in this action as well. *Gracey v. American Electric Power Company, Inc., et. al., Civ. No., 03-CV-7750 (U.S. District Court, Southern District of New York).*

C. In re Natural Gas Commodity Litigation

On December 5, 2003, the actions cited in paragraphs A and B above, were consolidated with other actions involving similar claims against other parties, in a civil action captioned *In re Natural Gas Commodity Litigation*, 03 CV 6186(VM), United States District Court, Southern District of New York. All further proceedings relative to these matters will be conducted in the consolidated action. The consolidated class action now includes claims against a number of companies, based upon a variety of alleged misconduct. The claims against Black Hills Corporation and Enserco comprise a relatively small part of only one category of the total claims included in this lawsuit. The action has not been certified to proceed as a class action. Motions to Dismiss were denied. Defendants will make an effort to "decertify" the matter as a class action based upon the dissimilarity of parties, claims and issues. While it is possible for an individual to state a claim for relief based upon allegations such as those made against Black Hills Corporation and Enserco, those Plaintiffs that have asserted claims against Black Hills Corporation and Enserco have a number of procedural and substantive hurdles to overcome. Even if Plaintiff's claims survive Motions to Dismiss, and successfully avoid class decertification, they still must prove actual damages as a result of the conduct of an individual Defendant, such as Black Hills Corporation and Enserco. Based upon information currently available, and given the current status of the litigation, we do not believe it is likely that Plaintiffs will be able to succeed in recovering on a claim in an amount that would be material to the Company's consolidated financial position or results of operations.

Acquisition Earn-Out Agreement Lawsuit

On August 13, 2004, the former shareholders of Indeck Capital, Inc. (Indeck) commenced litigation against the Company in United States District Court, Northeastern District of Illinois, Eastern Division. The lawsuit concerns the Company's performance of its obligation under the "Earn-out" provisions of the Agreement and Plan of Merger dated July 7, 2000, related to the Company's acquisition of Indeck. Under the "Earn-out" provisions, the former shareholders of Indeck were entitled to receive "contingent merger consideration" for a four year period beginning in 2000. The "contingent merger consideration" was not to exceed $35.0 million and was based on the acquired company's earnings over the four year period. As of December 31, 2004, $11.3 million has been either paid or offered for payment under the "Earn-out" provisions.

The lawsuit alleges that the Company failed to meet its obligation to produce documentation for its calculation of the contingent merger consideration, and in addition, failed to issue stock compensation in the full amount due to them. The Company denies these allegations and believes that it has fully and in good faith performed all of its obligations under the Agreement and Plan of Merger. In addition, the Company contends that the Agreement and Plan of Merger provides for mandatory arbitration as a medium for resolution of all disputes relating to the payment of contingent merger consideration, and will aggressively pursue the dismissal of the litigation. The outcome of this matter is uncertain, as is the amount of contingent merger consideration that could be awarded following arbitration or litigation.

Ongoing Proceedings

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 consolidated financial position or results of operations of the Company.

(22) GUARANTEES

The Company has entered into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees of debt obligations, contractual performance obligations and indemnification for reclamation and surety bonds.

As prescribed in FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45), the Company records a liability for the fair value of the obligation it has undertaken for guarantees issued after December 31, 2002. The liability recognition requirements of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002, while the disclosure requirements are applied to all guarantees.

As of December 31, 2004, the Company had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2004	Year Expiring
Guarantee payments under the Las Vegas Cogen I Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee of certain obligations under Enserco's credit facility	3,000	2005
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	500	2005
Guarantee payments of Black Hills Power under various transactions with Southern California Edison Company	750	2005
Guarantee obligations under the Wygen Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	28,213	2010
Guarantee payments of Las Vegas Cogen II to Nevada Power Company under a power purchase agreement	5,000	2013
Indemnification for subsidiary reclamation/surety bonds	25,420	Ongoing
	$ 184,651	

The Company has guaranteed up to $10.0 million of payments of its power generation subsidiary, Las Vegas Cogeneration Limited Partnership, to Sempra Energy Solutions which may arise from transactions entered into by the two parties under a Master Power Purchase and Sale Agreement. To the extent liabilities exist under this power and purchase sale agreement subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee may be terminated for future transactions upon five days written notice.

The Company has guaranteed up to $3.0 million of Enserco Energy Inc.'s obligations to Fortis Capital Corp. under its credit facility. There are no liabilities on the Company's Consolidated Balance Sheets associated with this guarantee.

The Company has guaranteed up to $0.8 million of the obligations of Las Vegas Cogeneration II, LLC under an interconnection and operations agreement for the LV II unit. To the extent liabilities exist under the interconnection and operations agreement, such liabilities are included in the Consolidated Balance Sheets. The obligation is due May 20, 2005.

The Company has guaranteed up to $0.5 million of the obligations of its electric utility subsidiary, BHP, under various transactions with Idaho Power Company. To the extent liabilities exist under these transactions and subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. This guarantee expired on March 1, 2005 and the Company issued a similar guarantee in the amount of $0.2 million on March 1, 2005.

The Company has guaranteed up to $0.8 million of the obligations of its electric utility subsidiary, BHP, under various transactions with Southern California Edison Company. To the extent liabilities exist under these transactions which are subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. This guarantee expires on the earlier of April 1, 2005 or 30 days after the date creditor receives written notification from guarantor.

The Company has guaranteed the obligations of Black Hills Wyoming under the Agreement for Lease and Lease for the Wygen plant. The Company consolidates the Variable Interest Entity that owns the plant into its financial statements; therefore the obligations associated with this guarantee are included in the Consolidated Balance Sheets. If the lease was terminated and sold, the Company's obligation is the amount of deficiency in the proceeds from the sale to repay the investors up to a maximum of 83.5 percent of the cost of the project. At December 31, 2004, the Company's maximum obligation under the guarantee is $111.0 million (83.5 percent of $133.0 million, the cost incurred for the Wygen plant). The initial term of the lease is five years with two five-year renewal options.

The Company has guaranteed the payment of $24.2 million of debt of Black Hills Wyoming and $4.0 million of debt for another of the Company's wholly-owned subsidiaries, Black Hills Generation. The debt is recorded on the Company's Consolidated Balance Sheets and is due December 18, 2010.

The Company has guaranteed up to $5.0 million of payments of its power generation subsidiary, Las Vegas Cogeneration II, LLC under the Western Systems Power Pool Confirmation Agreement with Nevada Power Company. To the extent liabilities exist under the agreements subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee expires upon payment in full of all the obligations under the contract, which expires in 2013.

In addition, at December 31, 2004, the Company had guarantees in place totaling approximately $25.4 million for reclamation and surety bonds for its subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in the Company's Consolidated Balance Sheets.

(23) BUSINESS SEGMENTS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2004, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six business segments that include: Wholesale Energy consisting of: Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region, Texas, California and other states; Energy Marketing and Transportation, which markets natural gas, oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regional markets; Power Generation, which produces and sells power and capacity to wholesale customers; and Retail Services consisting of: Electric Utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana and Communications, which primarily markets communications and software development services.

Prior to 2004, the Company's communications segment marketed campground reservation services and software development services to external parties through Daksoft, Inc. With the sale of certain assets and a change in its business strategy, Daksoft now primarily provides information technology support to the Company. With its focus now on corporate support, beginning with the first quarter 2004, Daksoft's results of operations are included with corporate results.

December 31:	2004	2003
	(in thousands)	
Total assets		
Wholesale energy:		
Coal mining	$ 55,310	$ 45,989
Oil and gas	194,203	145,371
Energy marketing and transportation	373,286	256,059
Power generation	826,240	876,160
Electric utility	464,361	463,869
Communications	116,373	126,204
Corporate	23,331	145,025
Discontinued operations	3,059	4,575
Total assets	$ 2,056,163	$ 2,063,252
Capital expenditures and acquisitions		
Wholesale energy:		
Coal mining	$ 3,183	$ 8,203
Oil and gas	53,891	43,448
Energy marketing and transportation	622	822
Power generation	6,043	28,798
Electric utility	13,347	25,427
Communications	8,101	8,178
Corporate	5,787	1,815
Total capital expenditures and acquisitions	$ 90,974	$ 116,691
Property, plant and equipment		
Wholesale energy:		
Coal mining	$ 73,367	$ 72,285
Oil and gas	259,695	205,137
Energy marketing and transportation	28,459	27,838
Power generation	792,385	791,684
Electric utility	637,278	622,849
Communications	165,351	159,534
Corporate	14,584	3,218
Total property, plant and equipment	$ 1,971,119	$ 1,882,545

December 31:	2004	2003 (in thousands)	2002
External operating revenues			
Wholesale energy:			
Coal mining	$ 19,669	$ 22,232	$ 20,811
Oil and gas	59,191	46,648	26,043
Energy marketing and transportation[(a)]	662,110	675,586	553,688
Power generation[(b)]	158,037	284,567	102,548
Electric utility	172,774	170,942	162,186
Communications	39,586	39,763	32,677
Corporate	761	—	—
Total external operating revenues	$1,112,128	$1,239,738	$ 897,953

(a) Operating revenues for energy marketing and transportation are presented in accordance with EITF 02-3 and EITF 99-19, as described in Note 1.
(b) Power generation revenue in 2003 includes $114 million of cot termination revenue as described in Note 13.

Intersegment operating revenues			
Wholesale energy:			
Coal mining	$ 12,298	$ 12,545	$ 10,524
Oil and gas	343	329	443
Electric utility	971	77	—
Corporate	2,672	—	—
Intersegment eliminations	(6,711)	(2,639)	(443)
Total intersegment operating revenues[(c)]	$ 9,573	$ 10,312	$ 10,524

(c) In accordance with the provisions of SFAS 71, intercompany fuel sales to the Company's regulated utility, Black Hills Power, are not eliminated.

Depreciation, depletion and amortization			
Wholesale energy:			
Coal mining	$ 5,142	$ 3,808	$ 3,358
Oil and gas	13,028	10,000	7,799
Energy marketing and transportation	1,201	1,183	932
Power generation	34,535	31,727	21,452
Electric utility	18,873	18,999	17,499
Communications	13,793	14,515	12,678
Corporate	1,261	559	147
Total depreciation, depletion and amortization	$ 87,833	$ 80,791	$ 63,865
Operating income (loss)			
Wholesale energy:			
Coal mining	$ 8,454	$ 8,775	$ 9,457
Oil and gas	19,181	13,258	6,471
Energy marketing and transportation	18,181	12,151	17,816
Power generation	47,934	58,893	35,362
Electric utility	43,809	51,099	58,160
Communications	(2,334)	(5,241)	(7,447)
Corporate	(1,306)	(7,767)	(7,103)
Total operating income	$ 133,919	$ 131,168	$ 112,716

December 31:	2004	2003 (in thousands)	2002
Interest income			
Wholesale energy:			
Coal mining	$ 1,393	$ 2,473	$ 3,459
Oil and gas	12	832	2
Energy marketing and transportation	728	1,236	1,634
Power generation	24,559	23,720	22,254
Electric utility	696	1,512	734
Communications	—	—	3
Corporate	15,626	16,090	16,680
Intersegment eliminations	(41,256)	(44,787)	(44,157)
Total interest income	$ 1,758	$ 1,076	$ 609
Interest expense			
Wholesale energy:			
Coal mining	$ 226	$ 757	$ 2,453
Oil and gas	1,578	2,054	59
Energy marketing and transportation	877	885	564
Power generation	49,758	53,854	41,454
Electric utility	16,019	17,044	13,663
Communications	3,748	3,827	3,993
Corporate	20,892	18,945	15,535
Intersegment eliminations	(41,256)	(44,787)	(44,157)
Total interest expense	$ 51,842	$ 52,579	$ 33,564
Income taxes			
Wholesale energy:			
Coal mining	$ 2,574	$ 2,423	$ 2,957
Oil and gas	5,315	3,978	1,739
Energy marketing and transportation	7,811	5,778	6,396
Power generation	6,711	11,795	7,430
Electric utility	9,512	11,622	15,067
Communications	(2,127)	(3,184)	(3,948)
Corporate	(3,092)	(2,811)	(2,997)
Total income taxes	$ 26,704	$ 29,601	$ 26,644
Income (loss) from continuing operations before change in accounting principle			
Wholesale energy:			
Coal mining	$ 7,463	$ 8,289	$ 8,131
Oil and gas	12,200	8,400	4,783
Energy marketing and transportation	10,222	6,725	12,739
Power generation	15,562	22,429	12,523
Electric utility	19,209	24,089	30,217
Communications	(3,941)	(5,880)	(7,260)
Corporate	(3,462)	(7,569)	(2,981)
Intersegment eliminations	(4)	(2)	(14)
Total income from continuing operations before change in accounting principle	$ 57,249	$ 56,481	$ 58,138

(24) ACQUISITIONS

On October 1, 2002, the Company entered into a definitive merger agreement to acquire the Denver-based Mallon Resources Corporation. On March 10, 2003, the Company completed this acquisition. The total cost of the transaction was approximately $51.2 million. The total cost of the transaction includes $30.5 million for the October 2002 acquisition of Mallon's debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges, and approximately $8.4 million, which the Company loaned to Mallon prior to completion of the acquisition. Mallon shareholders received 0.044 of a share of the Company's common stock for each share of Mallon, which was equivalent to 481,509 shares of Black Hills Corporation common stock.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price was allocated to the acquired assets and liabilities based on estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. The purchase allocation has been adjusted to reflect the completion of the quantification and analysis of the acquired asset retirement obligations in accordance with SFAS 143. This adjustment resulted in a $0.7 million increase to Long-term liabilities and Property, plant and equipment. The adjusted allocation of the purchase price is as follows (in thousands):

Current assets	$ 165
Property, plant and equipment	56,283
Deferred tax asset	5,194
Total assets acquired	$ 61,642
Current liabilities	$ 6,343
Long-term liabilities	4,146
Total liabilities assumed	$ 10,489
Net assets	$ 51,153

The results of operations of the above acquired company have been included in the accompanying consolidated financial statements since the acquisition date.

The following pro forma consolidated results of operations for the years ended December 31, have been prepared as if the Mallon acquisition had occurred on January 1, 2002 (in thousands):

	2003	2002
Operating revenues	$ 1,252,991	$ 919,538
Income from continuing operations	$ 56,033	$ 52,539
Net income available for common	$ 60,516	$ 55,630
Earnings per share —		
Basic:		
Continuing operations	$ 1.80	$ 1.92
Total	$ 1.95	$ 2.04
Diluted:		
Continuing operations	$ 1.78	$ 1.90
Total	$ 1.93	$ 2.02

The above pro forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that actually would have been achieved had the acquisition been consummated as of that time, nor is it intended to be a projection of future results.

Mallon Resources' proved developed and undeveloped reserves, estimated using constant year-end product prices, as of December 31, 2002, were approximately 86 billion cubic feet of gas equivalent. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering firm selected by the Company. The reserves are located primarily on the Jicarilla Apache Nation in the San Juan Basin of New Mexico and are comprised almost entirely of natural gas in shallow sand formations. The oil and gas leases of the acquisition total more than 66,500 gross acres (56,000 net), most of which is contained in a contiguous block that is in the early stages of development.

(25) SUBSEQUENT EVENTS

Cheyenne Acquisition

On January 13, 2004, the Company entered into a Stock Purchase Agreement to acquire from Xcel Energy, Inc. all of the outstanding capital stock of its subsidiary, CLF&P, a Wyoming corporation. On January 21, 2005, the Company completed this acquisition. The Company purchased all the common stock of CLF&P, including the assumption of outstanding debt of approximately $25 million, for approximately $90 million, plus a working capital adjustment to be finalized in the second quarter of 2005.

Cheyenne serves approximately 38,000 electric and 31,000 natural gas customers in Cheyenne and other parts of Laramie County, Wyoming. Its electric system peak load is 163 megawatts and power is supplied to the utility under an all-requirements contract with Public Service Company of Colorado, a subsidiary of Xcel Energy. The all-requirements contract expires in 2007. Annual gas distribution and transportation is approximately 5.0 million MMbtu.

Power Sales Agreement

The Company, through its subsidiary BHP, has entered into an agreement with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., to provide wholesale power for the City of Sheridan, Wyoming. Under the agreement, the Company will provide all requirements up to 74 megawatts of power to Montana-Dakota from January 1, 2007 through January 1, 2017. Power requirements above 74 megawatts are negotiable under terms specified in the agreement. The contract is pending approval by the Wyoming Public Service Commission. An existing contract provides up to 55 megawatts and expires January 1, 2007.

(26) OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (Unaudited)

Black Hills Exploration and Production has interests in 996 oil and gas properties in ten states and also holds leases on approximately 256,000 net acres.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the year ended December 31, (in thousands):

	2004	2003	2002
Acquisition of properties:			
Proved	$ 1,578	$ 21,075	$ 162
Unproved	231	19,994	2,331
Exploration costs	6,094	4,089	2,367
Development costs	39,258	19,377	11,699
Company's share of equity method investees' costs of property acquisition, exploration and development	392	1,067	—
	$ 47,553	$ 65,602	$ 16,559

Reserves

The following table summarizes Black Hills Exploration and Production's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2004, 2003 and 2002, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering company selected by the Company. Such reserve estimates are based upon a number of variable factors and assumptions, which may cause these estimates to differ from actual results.

	2004		2003		2002	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of barrels of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	5,389	124,062	4,880	28,513	4,055	24,071
Production	(432)	(9,456)	(405)	(8,548)	(455)	(4,707)
Additions	685	65,965	364	91,736	188	8,504
Property sales	(39)	(1,698)	—	—	(11)	—
Revisions to previous estimates	(364)	(36,890)	550	12,361	1,103	645
Balance at end of year	5,239	141,983	5,389	124,062	4,880	28,513
Proved developed reserves at end of year included above	4,608	80,366	4,830	66,294	4,188	27,473
Year-end prices (NYMEX)	$ 43.45	$ 6.15	$ 32.52	$ 6.19	$ 31.20	$ 4.60
Year-end prices (average well-head)	$ 41.19	$ 5.55	$ 30.56	$ 4.63	$ 29.24	$ 3.41

The 2004 reserve reconciliation reflected a 36.8 BCF downward revision to previous estimates. Approximately 70 percent of the revision is associated with our East Blanco Field in New Mexico. Since acquiring the field in March 2003, we have undertaken an extensive drilling and recompletion program. Overall, results of this development program have resulted in substantial reserve additions from numerous producing formations. However, our estimates for Proved Developed Non-Producing (PNP) and Proved Developed Behind Pipe (PBP) reserves, particularly in the multiple horizons of the Tertiary and Pictured Cliff zones, were revised downward based on actual results from our drilling and completion activities. In addition, many well locations which had been booked as Proved Undeveloped (PUD) and Proved Developed Non-Producing (PNP) in last year's reserve study were reclassified through drilling and completion activities to Proved Developed Producing (PDP) status by year-end 2004. Based on actual production history at the reclassified properties, reserve estimates for some well locations were revised downward.

The remaining 30 percent of downward reserve revisions were the result of various routine changes to engineering estimates, primarily due to additional production history.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31, (in thousands):

	2004	2003	2002
Unproved oil and gas properties	$ 20,148	$ 22,705	$ 5,109
Proved oil and gas properties	209,748	162,116	111,227
	229,896	184,821	116,336
Accumulated depreciation, depletion & amortization and valuation allowances	(75,870)	(61,928)	(56,488)
Net capitalized costs	$ 154,026	$ 122,893	$ 59,848
Company's share of equity method investees' net capitalized costs	$ 1,459	$ 1,067	$ —

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31, (in thousands):

	2004	2003	2002
Revenues			
Sales	$ 57,869	$ 43,458	$ 23,291
Production costs	19,991	14,432	6,310
Depreciation, depletion & amortization and valuation provisions	11,497	9,331	7,246
	31,488	23,763	13,556
Income tax expenses	5,342	3,953	1,668
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 21,039	$ 15,742	$ 8,067
Company's share of equity method investees' results of operations for producing activities	$ (120)	$ 337	$ —

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure as prescribed in SFAS 69, of discounted future net cash flows and related changes relating to proved oil and gas reserves for the years ended December 31, (in thousands):

	2004	2003	2002
Future cash inflows	$1,044,098	$ 794,555	$274,900
Future production and development costs	(409,478)	(339,732)	(124,451)
Future income tax expenses	(144,053)	(129,538)	(41,546)
Future net cash flows	490,567	325,285	108,903
10 percent annual discount for estimated timing of cash flows	(181,368)	(123,163)	(36,585)
Standardized measure of discounted future net cash flows	$ 309,199	$ 202,122	$ 72,318

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, (in thousands):

	2004	2003	2002
Standardized measure – beginning of year	$ 202,122	$ 72,318	$ 38,876
Sales and transfers of oil and gas produced, net of production costs	(45,266)	(29,026)	(16,981)
Net changes in prices and production costs	55,916	51,735	33,285
Extensions, discoveries and improved recovery, less related costs	168,516	9,064	15,700
Net changes in future development costs	21,852	32,757	2,202
Revisions of previous quantity estimates	(96,419)	26,632	11,839
Accretion of discount	26,534	9,417	4,375
Net change in income taxes	(22,028)	(41,372)	(16,978)
Purchases of reserves	4,062	70,597	—
Sales of reserves	(6,090)	—	—
Standardized measure – end of year	$ 309,199	$ 202,122	$ 72,318

(27) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following table sets forth selected unaudited historical operating results and market data for each quarter of 2004 and 2003.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2004				
Operating revenues	274,328	280,355	279,614	287,404
Operating income	28,306	27,274	37,313	41,026
Income from continuing operations	9,994	9,552	17,348	20,355
(Loss) income from discontinued operations, net of taxes	(208)	1,963	(168)	(863)
Net income	9,786	11,515	17,180	19,492
Net income available for common stock	9,698	11,437	17,102	19,415
Earnings per common share:				
Basic -				
Continuing operations	$ 0.31	$ 0.29	$ 0.53	$ 0.63
Discontinued operations	(0.01)	0.06	—	(0.03)
Total	$ 0.30	$ 0.35	$ 0.53	$ 0.60
Diluted -				
Continuing operations	$ 0.30	$ 0.29	$ 0.53	$ 0.62
Discontinued operations	—	0.06	(0.01)	(0.03)
Total	$ 0.30	$ 0.35	$ 0.52	$ 0.59
Dividends paid per share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Common stock prices				
High	$ 32.17	$ 32.49	$ 31.60	$ 31.68
Low	$ 29.19	$ 27.83	$ 26.52	$ 27.85

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2003				
Operating revenues	$ 291,445	$ 289,243	$ 410,860	$ 258,502
Operating income	35,504	30,330	39,044	26,290
Income from continuing operations before changes in accounting principles	15,698	13,507	17,673	9,603
Income from discontinued operations, net of taxes	1,160	3,153	4,771	852
Net income	14,178	16,660	22,444	7,940
Net income available for common stock	14,121	16,603	22,387	7,853
Earnings per common share:				
Basic -				
Continuing operations	$ 0.58	$ 0.44	$ 0.55	$ 0.29
Discontinued operations	0.04	0.10	0.15	0.03
Changes in accounting principles	(0.10)	—	—	(0.08)
Total	$ 0.52	$ 0.54	$ 0.70	$ 0.24
Diluted -				
Continuing operations	$ 0.58	$ 0.44	$ 0.54	$ 0.29
Discontinued operations	0.04	0.10	0.15	0.03
Changes in accounting principles	(0.10)	—	—	(0.08)
Total	$ 0.52	$ 0.54	$ 0.69	$ 0.24
Dividends paid per share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Common stock prices				
High	$ 28.39	$ 31.70	$ 33.54	$ 33.15
Low	$ 21.85	$ 27.00	$ 29.82	$ 27.76

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2004. Based on their evaluation, they have concluded that our disclosure controls and procedures are adequate and effective to ensure that material information relating to us that is required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the required time periods.

Internal control over financial reporting

Management's Report on Internal Control Over Financial Reporting is presented on page 78 of this Annual Report.

During our fourth fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding our directors and information required by Items 401 and 405 of Regulation S-K is incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2005.

Our Board of Directors has adopted a Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions. In addition, we have adopted Corporate Governance Guidelines for the Board of Directors, a Code of Business Conduct for our employees, and Charters for the Executive, Audit, Compensation and Governance Committees of the Board of Directors. The current version of these Corporate Governance Documents can be found on our Corporate Governance section of our Web site, *http://www.blackhillscorp.com/corpgov.htm* or a copy may be obtained without charge by contacting our Corporate Secretary. We intend to disclose any amendments to, or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and persons performing similar functions, on our Internet website.

Information required by Item 401(b) of Regulation S-K is presented as Item 4A herein as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding management remuneration and transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2005.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management and securities authorized for issuance under equity compensation plans is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2005.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 25, 2005.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement for the Annual Shareholder's Meeting to be held May 25, 2005.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Black Hills Corporation

We have audited the consolidated financial statements of Black Hills Corporation and subsidiaries (the "Corporation") as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, management's assessment of the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2004, and the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated March 10, 2005; such consolidated financial statements and reports are included elsewhere in the 2004 Annual Report on Form 10-K. Our audits also included the consolidated financial statement schedule of the Corporation listed in Item 15(a)(2). The consolidated financial statement schedule is the responsibility of the Corporation's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2005

(a) 1. Consolidated Financial Statements

Financial statements required by Item 15 are listed in the index included in Item 8 of Part II.

2. Schedules

Schedule II – Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2004, 2003 and 2002.

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in the Company’s consolidated financial statements and Notes thereto.

BLACK HILLS CORPORATION
SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

Description	Balance at beginning of year	Additions: Charged to costs and expenses	Additions: Other (a)	Deductions (b)	Balance at end of year
	(In thousands)				
Allowance for doubtful accounts:					
2004	$ 7,345	$ 1,434	$ —	$ (4,081)	$ 4,698
2003	3,226	2,358	2,810	(1,049)	7,345
2002	5,202	748	(823)	(1,901)	3,226

(a) Recoveries
(b) Uncollectible accounts written off

3. Exhibits

Exhibit Number	Description
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3.1	Restated Articles of Incorporation of the Registrant.
3.2*	Amended and Restated Bylaws of the Registrant dated December 20, 2002 (filed as Exhibit 3.3 to the Registrant's Form 10-K for 2002).
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10.5*†	Black Hills Corporation Nonqualified Deferred Compensation Plan dated June 1, 1999 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2000). First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan dated April 29, 2003 (filed as Exhibit 10.6 to the Registrant's Form 10-K for 2003).
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10.8*†	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2001).
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10.20*	Registration Rights Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 7 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.21*	Shareholders Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 8 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.22*	Compilation of the Amended and Restated Multi-year Credit Agreement dated as of August 21, 2003 among Black Hills Corporation, as Borrower, The Financial Institutions party thereto, as Banks, ABN AMRO BANK N.V., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent, BMO Nesbitt Burns Financing, Inc., as Co-Syndication Agent, US Bank, National Association, as Documentation Agent, and The Bank of Nova Scotia, as Co-Documentation Agent (filed as Exhibit 10.1 to the Registrant's Form 10-Q for June 30, 2004).
10.23*	364-day Credit Agreement dated as of May 13, 2004 among Black Hills Corporation, as Borrower, the Financial Institutions party thereto, as Banks, ABN AMRO Bank N.V., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent, Bank of Montreal dba "Harris Nesbitt," as Co-Syndication Agent, US Bank, National Association, as Documentation Agent and The Bank of Nova Scotia, as Co-Documentation Agent (filed as Exhibit 10.2 to the Registrant's Form 10-Q for June 30, 2004).

10.24*	Amended and Restated Credit Agreement dated as of May 14, 2004 among Enserco Energy, Inc., as Borrower, and Fortis Capital Corp., as administrative agent, collateral agent, documentation agent and arranger, and BNP Paribas, and U.S. Bank National Association and Societe Generale, and each other financial institution which may become a party hereto (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 6, 2004).
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23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
31.2	Certification pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Previously filed as part of the filing indicated and incorporated by reference herein.

† Indicates a board of director or management compensatory plan.

(b) See (a) 3. Exhibits above.

(c) See (a) 2. Schedules above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By /S/ DAVID R. EMERY
David R. Emery, President
and Chief Executive Officer

Dated: March 15, 2005

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, President and Chief Executive Officer	Director and Principal Executive Officer	March 15, 2005
/S/ MARK T. THIES Mark T. Thies, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	March 15, 2005
/S/ DANIEL P. LANDGUTH Daniel P. Landguth, Chairman	Director	March 15, 2005
/S/ BRUCE B. BRUNDAGE Bruce B. Brundage	Director	March 15, 2005
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 15, 2005
/S/ JACK W. EUGSTER Jack W. Eugster	Director	March 15, 2005
/S/ JOHN R. HOWARD John R. Howard	Director	March 15, 2005
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 15, 2005
/S/ RICHARD KORPAN Richard Korpan	Director	March 15, 2005
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	March 15, 2005
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 15, 2005

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* Previously filed as part of the filing indicated and incorporated by reference herein.

† Indicates a board of director or management compensatory plan.

Exhibit 3.1

RESTATED
ARTICLES OF INCORPORATION
OF
BLACK HILLS CORPORATION

Executed by the undersigned for the purpose of forming a South Dakota business corporation under Chapter 47 of SDCL.

ARTICLE I.

The name of the Corporation is Black Hills Corporation.

ARTICLE II.

The period of existence is perpetual.

ARTICLE III.

The purposes for which this Corporation is organized include, without limitation, to acquire, hold, purchase, sell, assign, transfer, exchange, mortgage, pledge, or otherwise dispose of shares of the capital stock of, or any bonds, securities or evidences of indebtedness created by, any other corporation of the state of South Dakota, or any other state, and, while the owner of such stock, to exercise all the rights, powers and privileges of ownership, including the right to vote thereon; to enter into plans of merger, consolidation, or exchange with any other corporation of the state of South Dakota or any other state; to aid in any manner any corporation or association, any shares of stock of which, or any bonds, debentures, notes, securities, evidences of indebtedness, contracts, or obligations of which, are held by or for the Corporation, or in which, or in the welfare of which, the Corporation shall have any interest; to do any acts designed to protect, preserve, improve or enhance the value of any property at any time held or controlled by the Corporation, or in which it may be at any time interested; to organize, promote, or facilitate the organization of subsidiary companies; to purchase, hold, sell and transfer shares of its own capital stock in the manner and to the extent provided by any law, rule or regulation; and to generally engage in any lawful act or activity and to enjoy and exercise all the rights, powers and privileges which are now or may hereafter be conferred upon corporations organized under the laws of the state of South Dakota. The foregoing clauses shall be construed both as objects and powers, and it is hereby expressly provided that the above enumeration of specific purposes and powers shall not be held to limit or restrict in any manner the purposes and powers of the Corporation, but is in furtherance of and in addition to the general powers conferred by the laws of the state of South Dakota.

ARTICLE IV.

The amount of total authorized capital stock of the Corporation is 125,000,000 shares consisting of:

A. 100,000,000 shares of Common Stock, having a par value of $1 per share; and

B. 25,000,000 shares of Preferred Stock, without par value.

ARTICLE V

A. Each holder of Common Stock shall at every meeting of the shareholders be entitled to one vote for each share of Common Stock held by him.

B. The Board of Directors of the Corporation is authorized, subject to limitations prescribed by law, to provide for the issuance of shares of Preferred Stock in series, and by filing a statement pursuant to the applicable law of the state of South Dakota, to establish from time to time the number of shares to be included in such series, and to fix the designations, powers, preferences and rights of the shares of each such series and the qualifications, limitations, and restrictions thereof.

The authority of the Board of Directors with respect to each series shall include, but not be limited to, determination of the following:

1) The number of shares constituting that series and the distinctive designation of that series;

2) The dividend rate on the shares of that series, whether dividends shall be cumulative, and, if so, from which date or dates, and the relative rights of priority, if any, of payment of dividends on the shares of that series;

3) Whether that series shall have voting rights, in addition to any voting rights provided by law, and if so, the terms of such voting rights, including, but not limited to, rights to elect a specified number of Directors in the event that dividends, if any, on Preferred Stock, remain unpaid for a specified period of time;

4) Whether that series shall have conversion privileges, and, if so, the terms and conditions of such conversion, including provisions for adjustment of the conversion rate in such events as the Board of Directors shall determine;

5) Whether or not the shares of that series will be redeemable, and, if so, the terms and conditions of such redemption, including the date or date upon or after which they shall be redeemable, and the amount per share payable in case of redemption, which amount may vary under different conditions and at different redemption dates;

6) Whether that series shall have a sinking fund for the redemption or purchase of shares of that series, and, if so, the terms and amount of such sinking fund;

7) The rights of the shares of that series in the event of voluntary or involuntary liquidation, dissolution, or winding up of the corporation, and the relative rights of priority, if any, of payment of shares of that series;

8) Any other relative rights, preferences, and limitations of that series.

Dividends on outstanding shares of Preferred Stock shall be paid or declared and set apart for payment before any dividends shall be paid or declared and set apart for payment on the Common Stock with respect to the same dividend period.

If upon any voluntary or involuntary liquidation, dissolution, or winding up of the Corporation, the assets available for distribution to holders of shares of Preferred Stock of all series shall be insufficient to pay such holders the full preferential amount to which they are entitled, then such assets shall be distributed ratably among the shares of all series of Preferred Stock in accordance with the respective preferential amounts (including unpaid cumulative dividends, if any) payable with respect thereto.

C. Neither the holders of the Common Stock nor the holders of any Preferred Stock shall have any preemptive rights to subscribe to any issue of stock or other securities of any class of the Corporation.

ARTICLE VI.

The business and affairs of the Corporation shall be managed by or under the direction of a Board of Directors, the number of which shall not be less than nine; provided, (i) the Board of Directors may change the number of Directors by amendments to its bylaws, and (ii) whenever the holders of any one or more series of Preferred Stock shall have the right, voting separately as a class, to elect one or more Directors of the Corporation, the number of Directors shall be increased to the extent necessary to give effect to such voting rights.

The Board of Directors shall be and is divided into three classes: Class I, Class II, and Class III, which shall be as nearly equal in number as possible, with the term of office of one class expiring each year. At the annual meeting of shareholders in 2000, Directors of the first class shall be elected to hold office for a term expiring at the next succeeding annual meeting; Directors of the second class shall be elected to hold office for a term expiring at the second succeeding annual meeting; and Directors of the third class shall be elected to hold office for a term expiring at the third succeeding annual meeting.

Any vacancies in the Board of Directors, for any reason, including any newly created directorships resulting from any increase in the number of Directors may be filled by the Board of Directors, acting by a majority of the directors then in office, although less than a quorum, and any Director so chosen shall hold office until the next election of the class for which such Director shall have been chosen.

The Board of Directors is expressly authorized to determine the rights, powers, duties, rules and procedures that affect the power of the Board of Directors to manage and direct the business and affairs of the corporation, including the power to designate and empower the committees of the Board of Directors, to elect, appoint and empower the officers and other agents of the corporation, and to determine the time and place of, and the notice requirements for, Board meetings as well as quorum and voting requirements for, and the manner of taking, Board action.

Each Director shall serve for a term continuing until the annual meeting of shareholders at which the term of the class to which he was elected expires and until his successor is elected and qualified or until his or her earlier death, resignation or removal; except a Director may be removed from office prior to the expiration of his or her term only for cause and by a vote of the majority of the total number of members of the Board of Directors without including the Director who is the subject of the removal determination and without such Director being entitled to vote thereon.

Notwithstanding anything contained in this Articles to the contrary, the affirmative vote or concurrence of the holders of at least 80 percent of the Common Stock entitled to vote thereon and 66 percent of the Preferred Stock entitled to vote thereon shall be required to alter, amend, or repeal this Article VI.

ARTICLE VII.

A. In addition to any other approvals and voting requirements mandated by law and other provisions of these Articles of Incorporation, the affirmative vote of the holders of not less than eighty percent (80%) of the outstanding shares of "Voting Stock" (as hereinafter defined) of this Corporation (the "Company") shall be required for the approval or authorization of any "Business Transaction" (as hereinafter defined) with any "Related Person" (as hereinafter defined) or any Business Transaction in which a Related Person has an interest (except proportionately as a shareholder of the Company); provided, the eighty percent (80%) voting requirement shall not be applicable if either:

1) the "Continuing Directors" (as hereinafter defined) of the Company by at least a majority vote thereof (a) have expressly approved in advance the acquisition of the outstanding shares of Voting Stock that caused such Related Person to become a Related Person, or (b) have expressly approved such Business Transaction; or

2) all of the following conditions (a), (b) and (c) shall have been met:

(a) the cash or fair market value (as determined by at least a majority of the Continuing Directors) of the property, securities or other consideration to be received per share by holders of Voting Stock of the Company (other than the Related Person) in the Business Transaction is not less than the "Highest Purchase Price" or the "Highest Equivalent Price" (as those terms are hereinafter defined) paid by the Related Person involved in the Business Transaction in acquiring any of its holdings of the Company's Voting Stock;

(b) the ratio of:

(w) the aggregate amount of the cash and the fair market value or other consideration to be received per share by holders of Common Stock in such Business Transaction, to

(x) the market price of the Common Stock immediately prior to the announcement of such Business Transaction,

is at least as great as the ratio of:

(y) the highest per share price (including brokerage commissions, transfer taxes and soliciting dealers' fees) which the Related Person involved in such Business Transaction has theretofore paid for any shares of Common Stock acquired by it, to

(z) the market price of the Common Stock immediately prior to the initial acquisition by such Related Person of any Common Stock; and

(c) the consideration to be received by holders of each class of capital stock in such Business Transaction shall be the same form and of the same kind as the consideration paid by the Related Person in acquiring the shares of that class of capital stock already owned by it.

B. For purposes of this Article VII:

1) The term "Business Transaction" shall include, without limitation, (a) any merger, consolidation or plan of exchange of the Company, or any entity controlled by or under common control with the Company, with or into any Related Person, or any entity controlled by or under common control with such Related Person, (b) any merger, consolidation or plan of exchange of a Related Person, or any entity controlled by or under common control with such Related Person, with or into the Company or any entity controlled by or under common control with the Company, (c) any sale, lease, exchange, transfer or other disposition (in one transaction or a series of transactions), including without limitation a mortgage or any other security device, of all or any "Substantial Part" (as hereinafter defined) of the property and assets of the Company, or any entity controlled by or under common control with the Company, to a Related Person, or any entity controlled by or under common control with such Related Person, d) any purchase, lease, exchange, transfer or other acquisition (in one transaction or a series of transactions), including, without limitation, a mortgage or any other security device, of all or any Substantial Part of the property and assets of a Related Person or any entity controlled by or under common control with such Related Person, by the Company or any entity controlled by or under common control with the Company, (e) any recapitalization of the Company that would have the effect of increasing the voting power of a Related Person, (f) the issuance, sale, exchange or other disposition of any securities of the Company, or of any entity controlled by or under common control with the Company, by the Company or by any entity controlled by or under common control with the Company, (g) any liquidation, spin-off, split-off, split-up or dissolution of the Company, and (h) any agreement, contract or other arrangement providing for any of the transactions described in this definition of Business Transaction.

2) The term "Related Person" shall mean and include (a) any individual, corporation, association, trust, partnership or other person or entity (a "Person") which, together with its "Affiliates" (as hereinafter defined) and "Associates" (as hereinafter defined), "Beneficially Owns" (as defined in Rule 13d-3 of the General Rules and Regulations under the

Securities Exchange Act of 1934 as in effect at March 27, 1986) in the aggregate ten percent (10%) or more of the outstanding Voting Stock of the Company, and (b) any Affiliate or Associate (other than the Company or a subsidiary of the Company of which the Company owns, directly or indirectly, more than eighty percent (80%) of the voting stock) of any such Person. Two or more Persons acting in concert for the purpose of acquiring, holding or disposing of Voting Stock of the Company shall be deemed a "Person."

3) Without limitation, any share of Voting Stock of the Company that any Related Person has the right to acquire at any time (notwithstanding that Rule 13d-3 deems such shares to be beneficially owned only if such right may be exercised within 60 days) pursuant to any agreement, contract, arrangement or understanding, or upon exercise of conversion rights, warrants or options, or otherwise, shall be deemed to be Beneficially Owned by such Related Person and to be outstanding for purposes of clause B(2) above.

4) For the purposes of subparagraph (2) of paragraph A. of this Article VII, the term "other consideration to be received" shall include, without limitation, Common Stock or other capital stock of the Company retained by its existing stockholders, other than any Related Person or other Person who is a party to such Business Transaction, in the event of a Business Transaction in which the Company is the survivor.

5) The term "Voting Stock" shall mean all of the outstanding shares of capital stock of the Company entitled to vote generally in the election of Directors, considered as one class, and each reference to a proportion of shares of Voting Stock shall refer to such proportion of the votes entitled to be cast by such shares.

6) The term "Continuing Director" shall mean any member of the Board of Directors of the Company (the "Board") who is unaffiliated with, and not a nominee of, the Related Person involved in a Business Transaction and was a member of the Board prior to the time that the Related Person became a Related Person and any successor of a Continuing Director who is unaffiliated with, not a nominee of, the Related Person and is designated to succeed a Continuing Director by a majority of Continuing Directors then on the Board.

7) A Related Person shall be deemed to have acquired a share of the Voting Stock of the Company at the time when such Related Person became the Beneficial Owner thereof. With respect to the shares owned by Affiliates, Associates or other Persons whose ownership is attributed to a Related Person under the foregoing definition of Related Person, if the price paid by such Related Person for such shares is not determinable by a majority of the Continuing Directors, the price so paid shall be deemed to be the higher of (a) the price paid upon the acquisition thereof by the Affiliate, Associate or other Person or (b) the market price of the shares in question at the time when such Related Person became the Beneficial Owner thereof.

8) The terms "Highest Purchase Price" and "Highest Equivalent Price" as used in this Article VII shall mean the following: If there is only one class of capital stock of the Company issued and outstanding, the Highest Purchase Price shall mean the highest price that can be determined to have been paid at any time by the Related Person involved in the Business Transaction for any share or shares of that class of capital stock. If there is more than one class

of capital stock of the Company issued and outstanding, the Highest Equivalent Price shall mean, with respect to each class and series of capital stock of the Company, the amount determined by a majority of the Continuing Directors, on whatever basis they believe is appropriate, to be the highest per share price equivalent to the highest price that can be determined to have been paid at any time by the Related Person for any share or shares of any class or series of capital stock of the Company. The Highest Purchase Price and the Highest Equivalent Price shall include any brokerage commissions, transfer taxes and soliciting dealers' fees paid by a Related Person with respect to the shares of capital stock of the Company acquired by such Related Person. In the case of any Business Transaction with a Related Person, the Continuing Directors shall determine the Highest Purchase Price or the Highest Equivalent Price for each class and series of the capital stock of the Company. The Highest Purchase Price and Highest Equivalent Price shall be appropriately adjusted to reflect the occurrence of any reclassification, recapitalization, stock split, reverse stock split or other readjustment in the number of outstanding shares of capital stock of the Company, or the declaration of a stock dividend thereon, between the last date upon which the Related Party paid the Highest Purchase Price or Highest Equivalent Price and the effective date of the merger or consolidation or the date of distribution to stockholders of the Company of the proceeds from the sale of all or substantially all of the assets of the Company.

9) The term "Substantial Part" shall mean ten percent (10%) or more of the fair market value of the total assets of the Person in question, as reflected on the most recent balance sheet of such Person existing at the time the stockholders of the Company would be required to approve or authorize the Business Transaction involving the assets constituting any such Substantial Part.

10) The term "Affiliate," used to indicate a relationship with a specified Person, shall mean a Person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the Person specified.

11) The term "Associate," used to indicate a relationship with a specified Person, shall mean (a) any entity of which such specified Person is an officer or partner or is, directly or indirectly, the beneficial owner of ten percent (10%) or more of any class of equity securities, (b) any trust or other estate in which such specified Person has a substantial beneficial interest or as to which such specified Person serves as trustee or in a similar fiduciary capacity, (c) any relative or spouse of such specified Person, or any relative of such spouse, who has the same home as such specified Person or who is a Director or officer of the Company or any of its subsidiaries, and (d) any Person who is a Director or officer of such specified Person or any of its parents or subsidiaries (other than the Company or an entity controlled by or under common control with the Company).

12) The term "subsidiary," when used to indicate a relationship with a specified Person, shall mean an Affiliate controlled by such Person directly, or indirectly through one or more intermediaries.

C. For the purposes of this Article VII, a majority of the Continuing Directors shall have the power to make a good faith determination, on the basis of information known to them, of: 1) the number of shares of Voting Stock that any Person Beneficially Owns, 2) whether a Person is an Affiliate or Associate of another, 3) whether a Person has an agreement, contract, arrangement or understanding with another or some other right as to the matters referred to in subparagraph B(1)(h) or B(3) hereof, 4) whether the assets subject to any Business Transaction constitute a Substantial Part, 5) whether any Business Transaction is one in which a Related Person has an interest (except proportionately as a shareholder of the Company), 6) the date of the initial acquisition of Common Stock by a Related Person, 7) whether the consideration to be received is in the same form as to the matter referred to in subparagraph A(2)(c), and 8) such other matters with respect to which a determination is required under this Article VII.

D. The provisions set forth in this Article VII may not be amended, altered, changed or repealed in any respect unless such action is approved by the affirmative vote of the holders of not less than eighty percent (80%) of the outstanding shares of Voting Stock of the Company.

ARTICLE VIII.

The Corporation will not commence business until consideration of the value of at least $1,000 has been received for issuance of shares.

ARTICLE IX.

The complete address, including the street address of the Corporation's registered office is 625 Ninth Street, Rapid City, South Dakota 57701, and the name of its registered agent at such address is Roxann R. Basham.

ARTICLE X.

The number of Directors constituting the initial Board of Directors is one and the name and address of the persons who is to serve as initial Director:

NAME	ADDRESS
Roxann R. Basham	625 Ninth Street, 4th floor P. O. Box 1400 Rapid City, SD 57709-1400

ARTICLE XI.

The name and address of the incorporator is:

NAME	ADDRESS
Roxann R. Basham	625 Ninth Street, 4th floor P. O. Box 1400 Rapid City, SD 57709-1400

ARTICLE XII.

Except as otherwise expressly provided by the laws of the State of South Dakota, the following additional provisions are inserted for the regulation of the business and for the conduct of the affairs of this Corporation and its Directors and shareholders:

A. No contract or other transaction between this Corporation and any other corporation shall be void or voidable because of the fact that Directors of this Corporation are Directors of such other corporation, if such contract or transaction shall be approved or ratified by the affirmative vote of a majority of the Directors present at a meeting of the Board of Directors, who are not so interested. Any Director individually, or any firm of which any Director is a partner, may be a party to or may be interested in any contract or transaction of this Corporation provided that such contract or transaction shall be approved or ratified by the affirmative vote of at least a majority of the Directors present at a meeting of the Board of Directors, who are not so interested, nor shall any Director be liable to account to this Corporation for any profit realized by him from or through any such transaction or contract of this Corporation, ratified or approved as aforesaid, by reason of his interest in such transaction or contract. Directors so interested may be counted when present at meetings of the Board of Directors for the purpose of determining the existence of a quorum.

B. The Board of Directors, in addition to the powers and authority expressly conferred upon it hereinbefore and by statute and by the Bylaws, is hereby empowered to exercise all such powers as may be exercised by the Corporation; subject, nevertheless, to the provisions of the laws of the State of South Dakota and of these Articles of Incorporation.

C. To the fullest extent permitted by South Dakota law governing this Corporation as the same exists or may hereafter be amended, a Director of this Corporation shall not be personally liable to the Corporation or its shareholders for monetary damages for breach of fiduciary duty as a Director, except for liability (i) for any breach of the Director's duty of loyalty to the Corporation or its shareholders, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) for any violation of ss.ss. 47-5-15 to 47-5-19, inclusive, of the South Dakota Codified Laws, or (iv) for any transaction from which the Director derived an improper personal benefit.

D. The provisions of South Dakota Codified Laws ss.ss. 47-33-8 through 47-33-16, inclusive, do not apply to control share acquisitions (as defined by South Dakota Codified Laws ss. 47-33-3(l)) of shares of this Corporation.

Dated this 22nd day of December, 2000.

/s/Roxann R. Basham
ROXANN R. BASHAM

Exhibit 21

BLACK HILLS CORPORATION

SUBSIDIARIES

Acquisition Partners, LP, a New York limited partnership

Adirondack Hydro Development Corporation, a Delaware corporation

Black Hills Cabrestro Pipeline, LLC, a Delaware limited liability company

Black Hills Colorado, LLC, a Delaware corporation

Black Hills Energy, Inc., a South Dakota corporation

Black Hills Energy Pipeline, LLC, a Delaware limited liability company

Black Hills Energy Resources, Inc., a South Dakota corporation

Black Hills Energy Terminal, LLC, a South Dakota limited liability company

Black Hills Exploration and Production, Inc., a Wyoming corporation

BHFC Publishing, LLC, a Delaware limited liability company

Black Hills FiberCom, LLC, a South Dakota corporation

Black Hills Fiber Systems, Inc., a South Dakota corporation

Black Hills Fountain Valley, LLC, a Delaware limited liability company

Black Hills Fountain Valley II, LLC, a Colorado limited liability company

Black Hills Gas Holdings Corp., a Colorado corporation

Black Hills Gas Resources, Inc., a Colorado corporation

Black Hills Generation, Inc., a Delaware corporation

Black Hills Idaho Operations, LLC, a Delaware limited liability company

Black Hills Independent Power Fund, Inc., a Texas corporation

Black Hills Ivanpah, LLC, a Delaware limited liability company

Black Hills Ivanpah GP, LLC, a Delaware limited liability company

Black Hills Kilgore Energy Pipeline, LLC, a Delaware limited liability company

Black Hills Kilgore Pipeline Company, L.P., a Texas limited partnership

Black Hills Kilgore Pipeline, Inc., a Delaware corporation

Black Hills Millennium Pipeline, Inc., a South Dakota corporation

Black Hills Millennium Terminal, Inc., a South Dakota corporation

Black Hills Nevada, LLC, a Delaware limited liability company

Black Hills Nevada Operations, LLC, a Delaware limited liability company

Black Hills Nevada Real Estate Holdings, LLC, a Delaware limited liability company

Black Hills Ontario, LLC, a Delaware limited liability company

Black Hills Operating Company, LLC, a Delaware limited liability company

Black Hills Pepperell Power Associates, LLC, a Delaware corporation

Black Hills Power, Inc., South Dakota corporation

Black Hills Publishing Montana, LLC, a Delaware limited liability company

Black Hills Service Company, LLC, a South Dakota limited liability company

Black Hills Southwest, LLC, a Delaware limited liability company

Black Hills Valmont Colorado, Inc., a Delaware corporation

Black Hills Wyoming, Inc., a Wyoming corporation

Cheyenne Light, Fuel and Power Company, a Wyoming corporation

Daksoft, Inc., a South Dakota corporation

Desert Arc I, LLC a Delaware limited liability company

Desert Arc II, LLC a Delaware limited liability company

E-Next A Equipment Leasing Company, LLC, a Delaware limited liability company

EIF Investors, Inc., a Delaware corporation

Enserco Energy, Inc., a South Dakota corporation

Fountain Valley Power, LLC, a Delaware limited liability company

Harbor Cogeneration Company, a California general partnership

Las Vegas Cogeneration II, LLC, a Delaware limited liability company

Las Vegas Cogeneration Energy Financing Company, LLC, a Delaware limited liability company

Las Vegas Cogeneration Limited Partnership, a Nevada limited partnership

Millennium Pipeline Company, L.P., a Texas limited partnership

Millennium Terminal Company, L.P., a Texas limited partnership

NHP, LP, a New York limited partnership

Sunco Ltd., a Nevada limited liability company

Varifuel, LLC

West Cascade Energy, LLC, a Delaware limited liability company

Wyodak Resources Development Corp., a Delaware corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Amendment No. 1 to Registration Statement No. 333-101541 and No. 33-71130 on Form S-3 and Registration Statement Nos. 33-63059, 333-61969, 333-17451, 333-82787, 333-30272, and 333-63264 on Form S-8 of Black Hills Corporation of our reports dated March 10, 2005, relating to the consolidated financial statements and financial statement schedule of Black Hills Corporation (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* and Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities,* effective January 1, 2003; Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities,* effective December 31, 2003; and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, effective January 1, 2002), and management's report of the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of Black Hills Corporation for the year ended December 31, 2004.

DELOITTE AND TOUCHE LLP

Minneapolis, Minnesota
March 10, 2005

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEER AND GEOLOGIST

As petroleum engineers, we hereby consent to the inclusion of the information included in this Form 10-K with respect to the oil and gas reserves of Black Hills Exploration and Production, Inc., the future net revenues from such reserves, and the present value thereof, which information has been included in this Form 10-K in reliance upon the report of this firm and upon the authority of this firm as experts in petroleum engineering. We hereby further consent to all references to our firm included in this Form 10-K and to the incorporation by reference in the Registration Statements on Form S-8 Nos. 33-63059, 333-61969, 333-17451, 333-82787, 333-30272 and 333-63264 and the Registration Statements on Form S-3, Nos. 33-71130 and 333-101541.

RALPH E. DAVIS ASSOCIATES, INC.

March 2, 2005

Exhibit 31.1

CERTIFICATION

I, David R. Emery, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2005

/s/ David R. Emery
President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2005

/s/ Mark T. Thies
Executive Vice President and
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2005

/s/ David R. Emery
David R. Emery
President and
Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the "Company") on Form 10-K for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark T. Thies, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2005

/s/ Mark T. Thies
Mark T. Thies
Executive Vice President and
Chief Financial Officer