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, 2005

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 if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No o

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No x

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 a large accelerated filer, an accelerated filer or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

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

At June 30, 2005 $1,194,433,716

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, 2006
Common stock, $1.00 par value	33,236,185 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 2006 Annual Meeting of Stockholders to be held on May 24, 2006, 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

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 without limitation 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 production from our 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 and profitably operate any future acquisitions;
- Unfavorable rulings in the periodic applications to recover costs for fuel and purchased power in our regulated utilities;
- The possibility that we may be required to take impairment charges to reduce the carrying value of some of our long-lived assets when indicators of impairment emerge;
- Numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs;
- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- Changes in business and financial reporting practices arising from the repeal of the Public Utility Holding Company Act of 1935 and other provisions of the recently enacted Energy Policy Act of 2005;
- 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 and availability 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 effective 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;
- The outcome of any ongoing or future litigation or similar disputes and the impact on any such outcome or related settlements;
- 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.

<u>**Overview**</u>

Black Hills Corporation, a South Dakota corporation, is a diversified energy company. 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: retail electric and gas service and wholesale energy.

Retail Services Group

In 2005, our retail services group conducted business in three segments:

Electric Utility. Through Black Hills Power, Inc. (Black Hills Power), our electric utility segment engages in the generation, transmission and distribution of electricity to approximately 63,500 customers in South Dakota, Wyoming and Montana, and the sale of electric energy and capacity on a wholesale, or “off-system,” basis.

Combination Electric and Gas Utility**.** On January 21, 2005, we acquired Cheyenne Light, Fuel and Power Company (Cheyenne Light), our combination electric and gas utility segment, which serves approximately 38,700 electric and 32,500 natural gas customers in Cheyenne, Wyoming and vicinity.

Communications**.** On June 30, 2005, we sold Black Hills Fiber Systems, Inc., through which we operated our communications segment, to PrairieWave Communications, Inc. Our communication segment offered broadband telecommunications services and operated a telephone directory business.

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 and sell natural gas and crude oil primarily in the Rocky Mountain region of the United States.

Coal Mining. We mine and sell 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 consists of two business segments – our regulated electric utility, Black Hills Power, and our regulated electric and gas utility, Cheyenne Light, which was acquired in late January 2005. It also consisted of our communications segment, Black Hills FiberCom and related businesses, which was sold June 30, 2005 and is reported as discontinued operations.

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 63,500 electric customers, with an electric transmission system of 447 miles of high voltage lines and 511 miles of lower voltage lines. In addition, Black Hills Power jointly owns 47 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 2005 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, 2005 was comprised of 26 percent commercial, 21 percent residential, 12 percent contract wholesale, 25 percent wholesale off-system, 11 percent industrial and 5 percent municipal sales and other revenue. Approximately 81 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 will continue to monitor our rate structure and when appropriate, file a rate case.

- 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 percent and Basin Electric owns 65 percent 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 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 entered into a new power purchase agreement with MDU for the supply of up to 74 megawatts of capacity and energy for Sheridan, Wyoming from 2007 through 2016, which is subject to regulatory approval by the WPSC; and

- an agreement with the City of Gillette, Wyoming, expiring in 2013, to provide the city's first 23 megawatts of capacity and energy. The agreement renews automatically and requires a seven year notice of termination.

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 401 megawatts in July 2005. 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 economically 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, which is operated by PacifiCorp, was placed into service in 1978 and operates as a baseload plant.

Combination Electric and Gas Utility Segment

We acquired Cheyenne Light in January 2005, and report its operations as a new segment within the retail services group.

Electric System. Cheyenne Light's electric system serves approximately 38,700 customers in Cheyenne, Wyoming and vicinity, and has a peak load of 163 megawatts. Power is supplied to Cheyenne Light under an all-requirements contract with PSCo, which expires at the end of 2007. For power needs after 2007, Cheyenne Light has a contract for 40 megawatts of energy and capacity from our Gillette CT, until August 2011, and 60 megawatts of energy and capacity from our Wygen I plant until the first quarter of 2013. Cheyenne Light is also in the construction phase of a coal-fired plant (Wygen II) near Gillette, Wyoming, which is expected to be in service the first quarter of 2008.

Natural Gas System. Cheyenne Light's natural gas distribution system serves approximately 32,500 natural gas customers in Cheyenne, Wyoming and vicinity. Cheyenne Light's annual natural gas sales and transportation from January 21, to December 31, 2005 were approximately 12.4 million Dekatherms (Dth), with sales to commercial and residential customers accounting for approximately 4.1 million Dth and transportation accounting for approximately 8.3 million Dth.

Cheyenne Light 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 certain transportation customers. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at Cheyenne Light's city gate meter station and a small amount is received directly from wellhead sources.

Wholesale Energy Group

Our wholesale energy group, which operates through Black Hills Energy, Inc. 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, storage and transportation of energy products. The wholesale energy group consists of four business segments for reporting purposes:

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

Power Generation Segment

Our power generation segment acquires, develops and operates unregulated power plants. We currently hold varying interests in independent power plants in Colorado, Nevada, Wyoming, California and Idaho with a total net ownership of 978 megawatts as of December 31, 2005, and minority interests in several power-related funds with a net ownership interest of 22 megawatts. In April 2005, we sold our 40 megawatt plant in Massachusetts.

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 91 percent natural gas-fired and 9 percent coal-fired. We sell capacity and energy under a combination of mid- to long-term contracts, which helps mitigate the impact of a potential downturn in power prices in the future. We also make certain “spot” sales into the energy markets. Currently, we sell approximately 99 percent of our unregulated generating capacity under contracts having terms of greater than one year, and we sell additional power into the wholesale power markets from our generating capacity when available and when it is economic to do so. We also mitigate our financial exposure in the power generation segment by selling a 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. As of December 31, 2005, we had approximately 978 net megawatts of name plate generating capacity in the Western Electricity Coordinating Council (WECC) states of Colorado, Nevada, Wyoming, California and Idaho, as follows:

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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	Gas	CO	130.0	100%	130.0	2000(1)
Valmont	Gas	CO	80.0	100%	80.0	2000 (2)
Las Vegas I	Gas	NV	53.0	100%	53.0	1994
Las Vegas II	Gas	NV	224.0	100%	224.0	2003
Gillette CT	Gas	WY	40.0	100%	40.0	2001
Wygen I (3)	Coal	WY	90.0	100%	90.0	2003
Ontario	Gas	CA	12.0	100%	12.0	1984
Harbor	Gas	CA	98.0	100%	98.0	1989 (4)
Rupert	Gas	ID	11.0	50%	5.5	1996
Glenns Ferry	Gas	ID	11.0	50%	5.5	1996
Total WECC			989.0		978.0	

(1) We completed a 50 MW expansion at Arapahoe in 2002.
(2) We completed a 40 MW expansion at Valmont in 2001.
(3) We hold our interest in Wygen I through a synthetic lease arrangement.
(4) We completed an 18 MW expansion at Harbor in 2001.

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. Prior to December 31, 2005, we had a 50 percent ownership in this plant, however under accounting principles generally accepted in the United States; we were required to consolidate 100 percent of the plant and its operations into our financial statements. On December 31, 2005, we purchased the remaining 50 percent interest in this facility that we did not already own (See Note 23 of Item 8., Financial Statements and Supplementary Data). 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. Regulatory approval for the new contract was obtained in March 2004 and we 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 I plant and Wyodak mine. The Gillette CT has a total capacity of 40 megawatts and became operational in May 2001. Prior to our ownership of Cheyenne Light, we entered into a 10-year power purchase agreement with Cheyenne Light, which expires in August 2011, for the sale of energy and capacity from this facility. In connection with PSCo's execution of an all-requirements power purchase agreement with Cheyenne Light, the Gillette CT power purchase agreement was assigned by Cheyenne Light to PSCo for the term of the all-requirements agreement, which expires December 31, 2007. Upon expiration of PSCo's all-requirements power purchase agreement with Cheyenne Light, the Gillette CT power purchase agreement reverts back to Cheyenne Light. During the remaining term of the temporary assignment, we assume intra-month fuel price risk 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 I Plant. The Wygen I 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 agreements to sell 60 megawatts of unit contingent capacity and energy from this plant to Cheyenne Light with a term of 10 years, expiring in the first quarter of 2013, and 20 megawatts of unit contingent capacity and energy to the Municipal Energy Agency of Nebraska (MEAN) for a term of 10 years, expiring February 2013. As with the Gillette CT power purchase agreement, Cheyenne Light has temporarily assigned the Wygen I 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 I plant under a synthetic lease arrangement, but under accounting principles generally accepted in the United States, we consolidate the plant and its operating activity in our financial statements.

Ontario Cogeneration Facility. Our Ontario facility, a QF, is a 12 megawatt, "Cheng-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 December 2009. The project also sells steam production to Sunkist Growers, Inc. under a five-year agreement, which terminates in November 2007. Prior to December 31, 2005, we had a 50 percent ownership in this plant, however under accounting principles generally accepted in the United States we were required to consolidate 100 percent of the plant and its operations into our financial statements. On December 31, 2005, we purchased the remaining 50 percent interest in this facility that we did not already own (See Item 8., Financial Statements and Supplementary Data).

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 commencing April 1, 2005, under which SCE purchases all of the capacity and energy of the facility 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.

Idaho Cogeneration Facilities. On December 31, 2005, we purchased a 50 percent interest in two QF facilities in Rupert and Glenns Ferry, Idaho (See Item 8., Financial Statements and Supplementary Data). Rupert and Glenns Ferry are both 11 megawatt, combined-cycle, gas-fired plants. Electrical output from the facilities is sold to Idaho Power Company under 20-year Energy Sales Agreements, which expire in late 2016. The projects also sell steam production to Idaho Fresh-Pak, Inc. under Thermal Energy Service Agreements, which also expire in late 2016. We had previously held notes receivable from the prior 50 percent owner secured by a pledge of the 50 percent interests; as such, while we did not own these interests prior to the acquisition, under accounting principles generally accepted in the United States, we accounted for, and continue to account for, 50 percent of the facilities operations in our financial statements under the equity method of accounting.

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. Additionally in April 2005, we sold our remaining assets in this region with the disposition of a 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 22 megawatts. We account for our investment in the funds under the equity method of accounting and as of December 31, 2005, had a $10.8 million investment balance in the funds.

Fund Name	Number of Plants	Total Capacity (MWs)	Interest	Net Capacity (MWs)
Energy Investors Fund I, L.P.	1	19.9	12.6%	2.5
Energy Investors Fund II, L.P.	3	37.2	6.9%	2.6
Project Finance Fund III, L.P.	6	250.6	5.3%	13.3
Caribbean Basin Power Fund, Ltd.	4	99.3	3.7%	3.7
Total Fund Interests		407.0		22.1

Project Development Program. Through our active project development program, we are pursuing the acquisition or development 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 portion 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 under state utility commission-approved contracts, or other investment-grade counterparties. 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 through our Black Hills Exploration and Production, Inc. subsidiary, is involved in the acquisition, exploration, development and production of natural gas and crude oil. As of December 31, 2005, we hold operated interests in oil and gas properties totaling approximately 527 wells located in the San Juan Basin of New Mexico and Colorado, the Powder River and Big Horn Basins of Wyoming, the Piceance Basin of Colorado, and the Denver Basin of Colorado and Nebraska. Unique to our San Juan Basin operations in New Mexico, we also own and operate a natural gas gathering pipeline along with associated gas compression and treating facilities. We hold non-operated interests in oil and natural gas properties totaling approximately 495 wells located in California, Colorado, Louisiana, Montana, North Dakota, Oklahoma, Texas and Wyoming.

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 plant is operated by Western Gas Resources.

The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region. Approximately 57 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 26 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field area of Weston and Niobrara counties. An expanding area of operated interests is in the Plateau and DeBeque Fields of the Piceance Basin of Colorado. In December 2005, the Company completed the acquisition of certain Piceance Basin gas assets from Red Oak Capital Management, LLC, Plateau Creek Partners, LP and other working interest owners in the Plateau Field, Mesa County, Colorado. In the transaction, the Company acquired approximately 13,000 net acres of oil and gas leasehold, and interests in a number of producing and shut-in wells. The acreage is mostly undeveloped. As of December 31, 2005, natural gas and oil comprise 76 percent and 24 percent of our total proved reserves, respectively. At December 31, 2005, we had total reserves of approximately 169.6 Bcfe.

On March 6, 2006, we entered into a definitive agreement to acquire certain oil and gas assets of Koch Exploration Company, LLC, including approximately 40.0 billion cubic feet of proved reserves, which are almost entirely natural gas, and associated midstream and gathering assets. The associated acreage position is in the Piceance Basin in Colorado and is comprised of leases covering more than 31,000 gross and 18,000 net acres, of which more than 48 percent of the lands are presently undeveloped. The acquisition includes 63 wells, of which 58 are operated by Koch Exploration. The acquisition is subject to further due diligence and is expected to close in the first quarter of 2006.

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, 2005, 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.

Proved Reserves:	December 31, 2005			December 31, 2004		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	6,724	10,635	50,979	5,169	9,065	40,079
New Mexico	43	96,641	96,899	15	115,121	115,211
Montana	30	3,032	3,212	18	2,836	2,944
Nebraska	—	5,391	5,391	—	5,034	5,034
Colorado	—	9,962	9,962	1	7,342	7,348
Other states	38	2,912	3,140	36	2,585	2,801
Total Proved Reserves	6,835	128,573	169,583	5,239	141,983	173,417

	December 31, 2005	December 31, 2004
Proved Developed Reserves, included in above total reserves:		
Natural gas (MMcf)	80,959	80,366
Oil (Mbbl)	4,694	4,608
Total (MMcfe)	109,123	108,014
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	64%	62%
Present value of estimated future net revenues, before tax (in thousands)	$ 560,023	$ 394,446

Drilling Activity

The following table reflects the wells completed through our drilling activities for the year ended December 31, 2005. In 2005, we participated in drilling 135 gross (70.87 net) development and exploratory wells, with a success rate of approximately 93 percent. Gross wells represent the total wells we participated in, regardless of ownership interest, with net wells representing our fractional ownership interests within those wells.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
Wyoming	21	1	22	1.46	1.00	2.46
New Mexico	38	1	39	37.08	1.00	38.08
Montana	37	3	40	6.96	0.67	7.63
Nebraska	17	1	18	17.00	0.50	17.50
Other states	12	4	16	4.38	0.82	5.20
Total	125	10	135	66.88	3.99	70.87

As of December 31, 2005, we were participating in the drilling of 27 gross (13.43 net) wells, which had been commenced but not yet completed.

Recompletion Activity

The following table reflects our recompletion activities for the year ended December 31, 2005.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
Wyoming	13	—	13	6.69	—	6.69
New Mexico	42	—	42	40.41	—	40.41
Montana	—	—	—	—	—	—
Nebraska	3	—	3	3.00	—	3.00
Other states	2	—	2	1.26	—	1.26
Total	60	—	60	51.36	—	51.36

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2005.

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	383	141	524	277.60	6.25	283.85
New Mexico	2	169	171	1.91	159.69	161.60
Montana	3	148	151	0.49	29.28	29.77
Nebraska	—	35	35	—	26.21	26.21
Colorado	—	41	41	—	19.42	19.42
Other states	8	92	100	1.58	19.45	21.03
Total	396	626	1,022	281.58	260.30	541.88

Acreage

The following table summarizes our undeveloped, developed and total acreage by state as of December 31, 2005 (in thousands).

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Wyoming	40	26	20	11	60	37
New Mexico	25	24	25	22	50	46
Montana	566	118	80	15	646	133
Nebraska	15	14	47	45	62	59
Colorado	23	17	7	5	30	22
Other states	29	13	64	13	93	26
Total	698	212	243	111	941	323

For more information on our oil and gas operations, see Note 25 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 4.7 million tons of coal in 2005. 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, 2005, we had coal reserves of approximately 290 million tons, based on an updated internal reserve study completed in 2005. The reserve life is equal to approximately 60 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 I; and
- certain regional industrial customers served by truck.

We also expect to increase our coal production to supply:

- additional mine-mouth generating capacity related to the 90 megawatt Wygen II plant, which is currently under construction and expected to achieve commercial operation by the first quarter of 2008 and is expected to utilize approximately 0.5 million tons of coal per year. The plant is being constructed at the Neil Simpson Complex near Gillette, Wyoming, and will be owned by Cheyenne Light;
- KFx, Inc. with up to 0.4 million tons under an agreement expiring at the end of 2006; and
- additional mine-mouth generating capacity at the Neil Simpson Complex related to the proposed Wygen III plant, which is currently in the development and permitting stage and would be expected to utilize approximately 0.5 million tons of coal per year.

Our coal mining segment sells coal to Black Hills Power for all of its requirements under an agreement that limits earnings from all coal sales to Black Hills Power, including the 20 percent share on the Wyodak plant and all sales to Black Hills Powers' other plants, to a specified return on our coal mine's cost-depreciated investment base. The return is 4 percent (400 basis points) above A-rated utility bonds, to be applied to our coal mining investment base as determined each year. 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 which terminates 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 physical volumes for the year ended December 31, 2005 were approximately 1.4 million MMBtu, or million British thermal units of gas, and 37,600 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 energy marketing operations focus primarily on producer services, end use origination and wholesale marketing services. 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. On January 5, 2006, we entered into an agreement with Sunoco Logistics Partners, L.P. to sell the operating assets of our crude oil marketing and oil pipeline systems. The transaction was completed on March 1, 2006. The sale included crude oil marketing and transportation operations headquartered in Houston, Texas, the 200-mile Millennium Pipeline System, the 190-mile Kilgore Pipeline System and related facilities.

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. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses. 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. In some instances, states are reevaluating their steps taken towards deregulation. South Dakota and Wyoming have not implemented retail competition.

In addition, Congress passed the Energy Policy Act of 2005. The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 and transferred oversight of holding companies to FERC effective February 8, 2006. On December 8, 2005 FERC issued final rules implementing the enactment of the Public Utility Holding Company Act of 2005, which are effective as of February 8, 2006. We cannot predict the long-term effect of such regulation or how FERC will interpret the new rules with any degree of certainty. As a result of these regulatory changes, significant additional competitors could become active in the utility, generation and power marketing segments of our industry.

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 various maximum 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 our marketing companies, and a credit committee, which oversees credit for the entire corporate organization. The risk management committee oversees the implementation of risk management procedures and the monitoring of our compliance with established policies. The credit committee monitors credit exposure levels and reviews compliance with established credit policies.

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 approved 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

Energy Policy Act of 2005. The Energy Policy Act of 2005 (EPA 2005) was signed into law on August 8, 2005. EPA 2005 repealed the Public Utility Holding Company Act of 1935 effective February 8, 2006 and transferred oversight of public utility holding companies to FERC. The rules under EPA 2005 require us to register with FERC as a public utility holding company and impose record keeping requirements and provide for oversight of affiliate transactions and service company allocations. EPA 2005 amended portions of the Federal Power Act and also amended portions of the PURPA relating to QFs including the elimination of ownership restrictions and a prospective repeal of the mandatory purchase and sale requirements for a QF if FERC finds that the QF has nondiscriminatory access to other markets.

Public Utility Holding Company Act of 1935. On December 28, 2004, we became a registered holding company under the Public Utility Holding Company Act of 1935. As a registered holding company, we were subject to regulatory oversight by the SEC. The rules and regulations imposed a number of restrictions on the operations of registered holding company systems. These restrictions included, 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. In connection with our registration, we formed a service company, Black Hills Service Company, L.L.C., to provide common services to affiliates such as accounting, administrative, information systems, engineering, financial, legal, maintenance and other services. With the passage of the Energy Policy Act of 2005, PUHCA was repealed and the oversight of public utility holding companies was transferred to FERC effective February 8, 2006.

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 of 1992. The passage of the Energy Policy Act of 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 subject to FERC regulation, including rate regulation. 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 a “material change” in facts occurs 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.

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, referred to as qualifying facilities (QFs). Prior to the enactment of EPA 2005, FERC’s regulations under PURPA required 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 and the enactment of EPA 2005 does not affect the existing contracts for these facilities.

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 rates in place during the freeze period 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;
- increased costs of fuel commodities;
- increased costs under power purchase contracts over which it has no control;
- government impositions; and
- acts of nature and other unexpected events that could cause material losses of income or increases in costs of doing business.

Cheyenne Light. Our Cheyenne Light 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. Cheyenne Light is subject to the jurisdiction of FERC with respect to accounting practices and the transmission of electricity in interstate commerce. All electric demand, purchased power and transmission costs are recoverable through an energy cost adjustment clause subject to WPSC jurisdiction. All purchased gas and transportation 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. In October 2005, the Wyoming Public Service Commission approved our application to increase Cheyenne Light’s base rates for gas and electric service effective on January 1, 2006.

Environmental Regulation

The construction and operation of power projects, coal mines, oil and gas properties, 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 I, 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 2035 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 March, 2005 the EPA issued mercury emission requirements for fossil fuel fired steam electric power plants. Wygen II and subsequent power plants will be subject to the emission standards as well as the monitoring, cap and trade requirements. Wygen I and Neil Simpson II will be subject to the monitoring, cap and trade requirements. Testing at Wygen I is planned for early 2006, to help gain understanding and knowledge of the mercury control and monitoring technology. Also there are several pending legal actions involving other parties, challenging various aspects of the mercury rule. 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 I, 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. The State of Wyoming is currently re-evaluating this practice and may, in the future, limit ash disposal to mined areas that are above future groundwater aquifers. This will result in increased costs, although those costs cannot be quantified until the exact requirements are known. None of the solid wastes from the burning of coal are classified as hazardous material, but the wastes do contain minute traces of metals that could 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 previously disposed of solid waste. 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 $16.0 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” 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, surplus 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.

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. Cheyenne Light, acquired in early 2005, has PCB test data provided by the previous owner, however we are implementing a program to retest and confirm results for all potentially PCB containing electrical equipment, except those requiring destruction of the device.

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, tribal 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;
- noise limitations;
- 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. Also in Rapid City, we own one additional office building consisting of approximately 19,900 square feet and a warehouse building and shop with approximately 25,200 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, 2006, we had 803 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)]	163
Wholesale Energy Group	243
Black Hills Power[(2)]	305
Cheyenne Light [(3)]	92
Total	803

(1) As of December 31, 2005, these employees were employed by Black Hills Corporation. With the formation of our service company, most of these employees were transferred to Black Hills Service Company, LLC on January 1, 2006.

(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 68 percent of our Cheyenne Light employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers (Local 111), which expires on June 30, 2008.

ITEM 1A. 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 and maintain dividends and debt payments. 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.

We cannot assure you that our results from any acquisition will conform to our expectations. There may be additional risks associated with the operation of any new acquisition.

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:

- delay in any required governmental or regulatory approvals;
- the loss of management or key personnel;
- the diversion of our management's attention from other business segments; and
- integration and operational issues.

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 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 with that agency 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 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 facility, our $128.3 million Wygen I plant project financing, and our $26.2 million General Electric Capital Corp. 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 and tensions between the United States and other governments 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 Cheyenne Light 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 Cheyenne Light, we agreed with the WPSC that Cheyenne Light would not raise retail rates for its 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 electricity 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.

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.

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:

- the Energy Policy Act of 2005 and the repeal of the Public Utility Holding Company Act of 1935;
- consumer demands;
- technological advances; and
- 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 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” subcaption within Item 8, Note 20, “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 2005.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 43, was elected Chairman in April 2005 and President and 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. Mr. Emery has 16 years of experience with us.

Thomas M. Ohlmacher, age 54, 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.

Linden R. Evans, age 43, was appointed President and Chief Operating Officer - Retail Business Segment in October 2004. Mr. Evans had been serving as the Vice President and General Manager of our former 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.

Mark T. Thies, age 42, has been our Executive Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. Mr. Thies has 8 years of experience with us.

Steven J. Helmers, age 49, 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 firm of Truhe, Beardsley, Jensen, Helmers & VonWald, from 1997 to January 2001.

Russell L. Cohen, age 45, 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.

Maurice T. Klefeker, age 49, 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.

James M. Mattern, age 51, has been the Senior Vice President – Corporate Administration and Compliance since April 2003 and Senior Vice President-Corporate Administration from September 1999 to April 2003. Mr. Mattern has 18 years of experience with us.

Roxann R. Basham, age 44, 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. Ms. Basham has a total of 22 years of experience with us.

Kyle D. White, age 46, has been Vice President – Corporate Affairs since January 30, 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White has 23 years of experience with us.

Garner M. Anderson, age 43, 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.

Perry S. Krush, age 47, 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.

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 March 1, 2006, we had 5,367 common shareholders of record and approximately 17,200 beneficial owners, representing all 50 states, the District of Columbia and 12 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 2006 meeting, our board of directors raised the quarterly dividend to $0.33 per share, equivalent to an annual dividend of $1.32 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, any regulatory restrictions 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 2.5:1.0, our recourse leverage ratio exceeds 0.65:1.00 or our consolidated net worth does not exceed the sum of $625 million and 50 percent of our aggregate consolidated net income since January 1, 2005.

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, 2005

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.32	$ 0.32	$ 0.32	$ 0.32
Common stock prices				
High	$ 33.32	$ 38.15	$ 43.50	$ 44.63
Low	$ 29.19	$ 32.63	$ 36.85	$ 33.67

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

UNREGISTERED SECURITIES ISSUED DURING THE FOURTH QUARTER OF 2005

No unregistered securities were issued during the fourth quarter of 2005.

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, 2005 - October 31, 2005	—	$ —	—	—
November 1, 2005 - November 30, 2005	2,271[(1)]	$ 29.36	—	—
December 1, 2005 - December 31, 2005	5,036[(2)]	$ 37.48	—	—
Total	7,307	$ 34.96	—	—

(1) Shares acquired by forfeiture of Restricted Stock.

(2) Includes 253 shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan, and 4,783 shares acquired from certain key employees under the share withholding provisions of the Restricted Stock Plan for payment of taxes associated with the vesting of shares of Restricted Stock.

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31,	2005	2004	2003	2002	2001
Total Assets (in thousands)	$ 2,119,960	$ 2,029,567	$ 2,044,555	$ 1,985,358	$ 1,643,461
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 1,958,059	$ 1,805,768	$ 1,725,302	$ 1,553,757	$ 1,249,046
Accumulated depreciation and depletion	522,661	468,840	397,499	349,061	281,362
Capital Expenditures (in thousands)	$ 208,856	$ 90,974	$ 116,691	$ 303,191	$ 594,142
Capitalization (in thousands)					
Long-term debt, net of current maturities	$ 670,193	$ 733,581	$ 868,459	$ 540,958	$ 329,771
Preferred stock equity	—	7,167	8,143	5,549	5,549
Common stock equity	738,879	728,598	701,604	529,614	509,615
Total capitalization	$ 1,409,072	$ 1,469,346	$ 1,578,206	$ 1,076,121	$ 844,935
Capitalization Ratios					
Long-term debt, net of current maturities	47.6%	49.9%	55.0%	50.3%	39.0%
Preferred stock equity	—	0.5	0.5	0.5	0.7
Common stock equity	52.4	49.6	44.5	49.2	60.3
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues (in thousands)	$ 1,391,644	$ 1,082,115	$ 1,212,040 (1)	$ 877,182	$ 717,493
Net Income Available for Common (in thousands):					
Wholesale energy	$ 28,687	$ 45,447	$ 45,843	$ 38,176	$ 54,701
Retail services	20,119	19,209	23,999	30,138	45,131
Corporate expenses and intersegment eliminations	(13,046)	(3,466)	(7,571)	(2,995)	(3,284)
Income from Continuing Operations Before Changes in Accounting Principles	35,760	61,190	62,271	65,319	96,548
Discontinued operations	(2,340)	(3,217)	4,146	(4,763)	(8,471)
Changes in accounting principles, net of tax	—	—	(5,195)	896	—
Preferred dividends	(159)	(321)	(258)	(223)	(527)
	$ 33,261	$ 57,652	$ 60,964	$ 61,229	$ 87,550
Dividends Paid on Common Stock (in thousands)	$ 42,053	$ 40,210	$ 37,025	$ 31,116	$ 28,517
Common Stock Data (in thousands)					
Shares outstanding, average	32,765	32,387	30,496	26,803	25,374
Shares outstanding, average diluted	33,288	32,912	31,015	27,167	25,771
Shares outstanding, end of year	33,156	32,478	32,298	26,933	26,652
Earnings Per Share of Common Stock (in dollars)(2)					
Basic earnings (losses) per average share -					
Continuing operations	$ 1.09	$ 1.88	$ 2.03	$ 2.43	$ 3.78
Discontinued operations	(0.07)	(0.10)	0.14	(0.18)	(0.33)
Change in accounting principle	—	—	(0.17)	0.03	—
Total	$ 1.02	$ 1.78	$ 2.00	$ 2.28	$ 3.45
Diluted earnings (losses) per average share -					
Continuing operations	$ 1.07	$ 1.86	$ 2.01	$ 2.40	$ 3.75
Discontinued operations	(0.07)	(0.10)	0.13	(0.17)	(0.33)
Change in accounting principle	—	—	(0.17)	0.03	—
Total	$ 1.00	$ 1.76	$ 1.97	$ 2.26	$ 3.42
Dividends Paid per Share	$ 1.28	$ 1.24	$ 1.20	$ 1.16	$ 1.12
Book Value Per Share, End of Year	$ 22.28	$ 22.43	$ 21.72	$ 19.66	$ 19.12
Return on Average Common Stock Equity (year end)	4.5%	8.1%	9.9%	11.8%	22.2%

Operating Statistics:

Years ended December 31,	2005	2004	2003	2002	2001
Generating capacity (megawatts):					
Utility (owned generation)	435	435	435	435	395
Utility (purchased capacity)	50	50	55	60	65
Independent power generation(3)	1,000	1,004	1,002	950 (4)	617
Total generating capacity	1,485	1,489	1,492	1,445	1,077
Electric utility sales (megawatt-hours):					
Retail electric sales	1,582,841	1,509,635	1,536,836	1,515,635	1,568,453
Contracted wholesale sales	619,369	614,700	614,888	757,051	756,206
Wholesale off-system	869,161	926,461	773,801	673,051	652,725
Total utility electric sales	3,071,371	3,050,796	2,925,525	2,945,737	2,977,384
Electric and gas utility sales:					
Electric megawatt-hours	889,210	—	—	—	—
Gas sales dekatherms	4,062,590	—	—	—	—
Gas transport dekatherms	8,286,338	—	—	—	—
Oil and gas production sold (MMcfe)	13,745	12,595	10,843	7,398	7,293
Oil and gas reserves (MMcfe)	169,583	173,417	156,396	57,793	48,401
Tons of coal sold (thousands of tons)	4,702	4,780	4,812	4,052	3,518
Coal reserves (thousands of tons)	290,000	294,000	263,000	273,000	277,000
Average daily marketing volumes:					
Natural gas physical sales (MMbtus)	1,427,400	1,226,600	897,850	683,500	543,000
Natural gas financial sales (MMbtus)	709,200	514,500	344,050	404,700	504,700
Crude oil barrels marketed	37,600	44,900	58,700	57,200	36,500
Crude oil barrels transported	37,000	52,300	58,300	42,100	16,800

We have experienced significant change over the last five years, primarily as a result of the expansion of our wholesale energy business, commodity price volatility and volatility in wholesale electric sales and the related margins at our electric utility, Black Hills Power. Unusual conditions in the Western energy markets during the first half of 2001 accounted for approximately $1.40 per share of our earnings in 2001. Impairment charges recorded to reduce the carrying value of long-lived assets to fair value were approximately $33.9 million after-tax in 2005, and approximately $76.2 million after-tax in 2003.

During 2005 we acquired Cheyenne Light, which is referred to as our Electric and gas utility segment. In addition, certain items related to 2001 through 2004 have been restated from prior year presentations to reflect the classification of Black Hills FiberSystems, Inc. as discontinued operations in 2005 (see Notes 1 and 18 of Item 8. Financial Statements and Supplementary Data).

(1)Includes $114.0 million of contract termination revenue.
(2)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.
(3)Includes 40 MWs in 2004 and 2003, respectively, 82 MWs in 2002 and 68 MWs in 2001, which have been 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., which have been reported as “Discontinued operations.”

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 22 OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

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

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

Our retail services group currently consists of our electric utility, Black Hills Power, and our electric and gas utility, Cheyenne Light, which was acquired January 21, 2005. Our electric utility, Black Hills Power, Inc., generates, transmits and distributes electricity to approximately 63,500 customers in South Dakota, Wyoming and Montana. Our electric and gas utility serves approximately 38,700 electric customers and 32,500 natural gas customers in Cheyenne, Wyoming and vicinity. 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.

In June 2005, we sold our subsidiary, Black Hills FiberSystems, Inc., previously reported as our Communications segment. In April 2005, we also sold our Pepperell power plant, our last remaining power plant in the eastern region, which was previously reported in our Power generation segment. 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. Prior period results have been reclassified to present the financial information as Discontinued operations.

On January 5, 2006, we announced that we had entered into a definitive agreement to sell the operating assets of our oil marketing and transportation business. The transaction was completed on March 1, 2006. These assets and their operating results have been included in this Annual Report on Form 10-K as part of our energy marketing and transportation segment. Beginning with the first quarter of 2006, the assets and their operating results will be classified as part of Discontinued operations.

Industry Overview

The overall energy industry improved its financial performance in 2005 on steady demand for products and services and strong wholesale prices for natural gas and oil. The industry also experienced significant challenges, such as the devastating effect of hurricanes, which curtailed gas and oil production in and around the Gulf of Mexico and disrupted utilities' service across vast regions, and the effects of soaring natural gas, oil and coal prices on consumers of those commodities. International tensions, particularly in the Middle East, are contributing to the volatile condition of current energy markets. Uncertainties associated with foreign sources of crude oil imports and increasing demand for crude oil in foreign markets have influenced domestic energy prices in recent months, and future price indexes are at much higher levels than were expected a year ago.

While the energy industry is increasingly competitive due to economic change and technological innovation, the regulatory environment is likely in a transitional phase. The repeal of PUHCA effective in February 2006, and many of its restrictions on utility merger and acquisition activities, suggests that consolidation of utilities could occur in certain parts of the U.S. in the months and years ahead. At the federal level, transmission issues continue to receive significant attention as physical constraints and the need for more infrastructure investment becomes increasingly apparent.

The consequences of electric deregulation efforts of the 1990's continue to challenge regulators. 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 to open markets to competition. Due to a number of causes, energy consumers in some jurisdictions have been exposed to significant price increases and deterioration in service in recent years.

In 2005, state-level public utility commissions continued to evaluate the merits of regulated versus non-regulated environments for utilities. Relations between investor owned utilities and regulators seemed to improve and progress was made on multi-year rate cases in several jurisdictions. In a period of high costs of fuel for power generation, industrial use and home heating, it is expected that regulators will strive to keep rates reasonable, including allowing some electric utilities to revert to vertically integrated structures again. Because the benefits of a more competitive industry were not always evident, many regulators are now seeking new policy directions to assure greater stability and end-user value in the future.

A surge in investment in gas-fired power generation facilities occurred in the early 2000's. Some of that investment led to an overabundance of power capacity in certain regions of the country. In many instances, "merchant" or non-contracted plants became financially distressed as market prices for power fell below the cost of production for extended periods in the 2002-2005 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 recent years, 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 three years. However, in December 2005, power prices surged in response to weather-related demand. Extreme pricing was short-lived as weather returned to a milder pattern. The quick response of the marketplace demonstrates that a resurgence of either colder winter months, a hotter than normal summer peaking season or increases in industrial demand could again cause volatile prices. 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. In the current winter season of snow pack and moisture accumulation in watersheds feeding reservoirs in the Pacific Northwest, conditions point to improved hydroelectric performance relative to the last few years.

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 cumulative 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 have abandoned unsuccessful business strategies, sold non-core assets, downsized staffs, issued new equity, canceled acquisitions, postponed or canceled construction projects, reduced significant levels of capital expenditures, accelerated debt repayment and realigned trading around their own generation, mid-stream and transportation assets. In 2005, the energy industry generally showed improved financial condition and stronger balance sheets along with adequate liquidity and access to capital markets.

The oil and gas industry has experienced significant price volatility in the past several years, from a relatively lower-price environment in 2002 and 2003 to significantly higher prices for both commodities in 2005. In the 2000's, natural gas has emerged as the national industrial fuel of choice because of its emissions characteristics, and demand has expanded significantly. For example, 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 favorable fuel 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 resurgence in the past few years, with favorable commodity prices creating attractive returns. Coal prices in Wyoming's Powder River Basin have increased dramatically in 2005, despite its lower heat content characteristics and higher transportation costs. From a regional perspective, Powder River Basin coal is 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 a significant portion of a national energy mix remains strong.

Business Strategy

We are a customer-focused diversified energy provider. Our business is comprised of fuel assets, electric generation assets and retail utility assets, including 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 stronger 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, energy marketing and retail utility operations is supported by disciplined risk management practices.

Our long-term strategy is to continue growing our core retail utility, generation and fuel asset businesses, supplemented by our energy marketing operations. We will do this primarily by focusing on providing superior economic and performance value to customers and increasing our customer base. 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. In the fuel area, we will continue to strive to maintain our positive relationships with mineral owners and regulatory authorities and work to develop additional markets for our production, including the development of additional power plants at our mine site. The expertise of our energy marketing business 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 and natural gas products and services. The wholesale component consists of fuel production, marketing, mid-stream assets and power production facilities;
- review Black Hills Power’s 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;
- invest in rate-base generation to serve our electric utilities;
- expand retail operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages;
- build and maintain strong relationships with wholesale power customers;
- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;
- sell a large percentage of our capacity and energy production from 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 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, as warranted by the market, natural gas storage and transportation; 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 natural gas 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.

Review Black Hills Power's 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 power supply resources 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. We will continue to monitor our rate structure and when appropriate, we will file a rate case.

Invest in Rate-Base Generation to Serve our Electric Utilities. Our Company's original business was a vertically integrated electric utility. This business model remains a core strength today, where we operate efficient power generation resources to transmit and distribute electricity to our customers. By doing so, we provide power at reasonable and stable rates to our customers and earn solid returns to our investors. Rate-based generation assets offer several advantages for consumers, regulators and investors. First, they assure consumers that rates have been reviewed and approved by government authorities who are safeguarding the public interest. Second, regulators are given the opportunity to participate in a planning process where long-term investments are designed to match long-term energy demand. Third, investors are assured that a long-term, reasonable, stable rate of return may be earned on their investment. A lower risk profile may also improve credit ratings which, in turn, can benefit both consumers and investors, by lowering the cost of capital to the Company.

Expand Retail Operations Through Selective Acquisitions of Electric and Gas 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 Cheyenne Light and the November 2005 non-binding offer to combine with Northwestern Corporation are examples of such 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.

Build and Maintain Strong Relationships With Wholesale Power 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 risk committee that reports to our board of directors.

Sell a Large Percentage of our Capacity and Energy Production From 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 majority of our unregulated power generation 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 and currently with the ongoing construction of the Wygen II facility. We believe that our Fountain Valley, Harbor, 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 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 existing oil and natural gas operations as well as 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 primary 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 by continuing to develop additional mine-mouth generating facilities at the site; and

- pursue future sales of coal to additional regional rail-served and truck-served customers.

Grow our Energy Marketing Operations Primarily Through the Expansion of Producer and End-use Origination Services and, as Warranted by the Market, Natural Gas Storage and Transportation. Our energy marketing business seeks to provide services to producers and end-users of natural gas, and to capitalize on market volatility by utilizing storage, transportation and proprietary trading positions. The service provider focus of our energy marketing activities is what largely differentiates us from other energy marketers. Through our producer services group we assist mostly small to medium sized producers throughout the Western U.S. with marketing and transporting their natural gas to market. Through our wholesale marketing division we work with utilities, municipalities and industrial users of natural gas to provide customized delivery services as well as to support their efforts to optimize their transportation and storage positions. In the future, we may add other energy commodities to our marketing portfolio or seek to acquire mid-stream assets, such as regional pipelines, so we can further facilitate and 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 our marketing operations 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 credit facilities separate from our corporate facility.

Prospective Information

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.

Retail Services Group

Electric Utility

Firm electric business at our electric utility, Black Hills Power, remained strong in 2005. 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 more than 10 years, do not include fuel and/or purchased power adjustment clauses, but allow Black Hills Power to retain the benefits of off-system wholesale sales and cost reductions. Black Hills Power's return is affected by changes in fuel prices, inflation, capital investment, capital markets, and retail and wholesale power sales. We will monitor these potential impacts in order to ensure that our return remains adequate for its investment to serve customers. If necessary, increases to rates will be sought through the regulatory process.

Electric and Gas Utility

We acquired Cheyenne Light on January 21, 2005. We requested and received approval from the WPSC for a rate increase that went into effect on January 1, 2006 and will increase annual revenues by an expected $4.8 million. We also expect additional costs in 2006 related to allocated corporate costs to total approximately $2.7 million. We began construction on Wygen II, a 90-megawatt baseload coal-fired power plant. The plant will be a regulated asset of Cheyenne Light. The facility is expected to cost approximately $169 million, including interim financing costs during construction. This power plant is expected to be in commercial operation in early 2008 and will require a future rate review with the WPSC in order to recover capital and provide a return on invested capital. Presently, power is provided by Public Service Company of Colorado under an all-requirements contract, which expires December 31, 2007.

Wholesale Energy Group

Power Generation

We expect lower earnings, excluding the impairment charges in 2005, from our Power Generation segment in 2006 primarily as a result of maintenance issues at our Las Vegas facility. In January 2006, the Las Vegas II plant was taken off line for diagnosis and initiation of repairs of both of its heat recovery steam turbine generators. We have restored two-thirds of the plant capacity and energy availability through simple-cycle generation but expect the maintenance period to extend into the second quarter of 2006. The negative financial impact of this unplanned outage is under evaluation, and is currently expected to be in the range of $0.05 to $0.08 per share. At the Las Vegas I power plant, an extensive maintenance program initiated in the fourth quarter of 2005 continues, and plant repairs and upgrades are expected to be completed in April 2006.

Significant earnings provided by power fund investments in 2005 are not expected in 2006 and beyond. During 2005 two of the funds in which we invest liquidated a substantial portion of their underlying power plant investments, generally realizing large gains over the expected fair market value, and a third fund achieved certain performance thresholds that triggered an “equity flip” increasing our ownership interest, from which we recorded a benefit.

Oil and Gas

We expect that earnings from this segment over the next few years will be driven primarily by increased oil and gas production. Driven by our March 2003 acquisition of Mallon Resources and the ongoing subsequent development of these properties, our compound annual production growth on a per Mcfe basis has been approximately 23 percent since our 2002 pre-acquisition level. Our long-term compound annual production growth target is 10 percent. In 2006 we expect to achieve our production growth target and benefit from a strong pricing environment, even while drilling and completion costs continue to rise, as shortages persist in the industry.

We expect to deploy approximately $70-$75 million of capital in 2006 developing our current properties, including the Piceance Basin gas assets acquired from Red Oak Capital Management, LLC in December 2005. This forecast does not include the acquisition or future development costs of the Koch properties that we entered into a definitive agreement to acquire during March 2006. Our drilling program is focused on both proved reserves and the further delineation of existing fields. We have also commenced an oil well development drilling program on our existing properties in northeast Wyoming.

Energy Marketing and Transportation

On March 1, 2006 we completed the sale of our crude oil marketing and transportation assets with a sales price of approximately $41.0 million. We expect to record a gain on the sale and cash proceeds are expected to be used for debt reduction or other corporate purposes. Beginning with the first quarter of 2006, operating results from these assets will be classified as Discontinued operations and will not contribute to the earnings of this segment in 2006. Earnings from these operations were approximately $2.5 million in 2005. In addition, due to the required gross presentation of crude oil marketing revenues and cost of sales, future revenues and operating expenses will decrease significantly while having no significant impact on earnings. During 2005, revenues and cost of sales generated from the operating assets sold were $778.1 million and $765.2 million, respectively.

Coal Mining

We expect lower earnings from our Coal Mining operations in 2006 resulting from a major planned outage at the Wyodak power plant, the mine’s largest customer. The outage is expected to last approximately six weeks and occur during the second quarter of 2006.

Results of Operations

Consolidated Results

Overview

Revenue and income (loss) from continuing operations provided by each business group were as follows (in thousands):

	2005	2004	2003
Revenue:			
Retail services	$ 297,681	$ 172,774	$ 172,695
Wholesale energy	1,093,192	908,580	1,039,345
Corporate	771	761	—
	$ 1,391,644	$ 1,082,115	$ 1,212,040

	2005	2004	2003
Income (loss) from continuing operations:			
Retail services	$ 20,119	$ 19,205	$ 23,997
Wholesale energy	28,687	45,447	45,843
Corporate	(13,046)	(3,462)	(7,569)
	$ 35,760	$ 61,190	$ 62,271

In June 2005, we sold our subsidiary, Black Hills FiberSystems, Inc., previously reported as our communications segment. In April 2005, we also sold our Pepperell power plant, our last remaining power plant in the eastern region, which was previously reported in our power generation segment.

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 September 2003, we sold our hydroelectric power plants located in upstate New York. These discontinued operations were previously reported in the power generation segment.

Results of operations for 2004 and 2003 have been restated to reflect the operations discontinued.

2005 Compared to 2004

Consolidated income from continuing operations for 2005 was $35.8 million, compared to $61.2 million in 2004, or $1.07 per share in 2005, compared to $1.86 per share in 2004. Loss from discontinued operations was $(2.3) million or $(0.07) per share in 2005, compared to loss of $(3.2) million or $(0.10) per share in 2004. Return on average common equity in 2005 and 2004 was 4.5 percent and 8.1 percent, respectively.

The wholesale energy group’s income from continuing operations decreased $16.8 million in 2005 compared to 2004. Decreased earnings from power generation of $28.1 million and from coal mining of $0.5 million were offset by increased income from continuing operations of $5.7 million at our oil and gas operations and $6.1 million from energy marketing and transportation operations.

The retail services group’s income from continuing operations increased $0.9 million in 2005 compared to 2004. Earnings from the electric and gas utility, acquired January 21, 2005, were $2.1 million and earnings from continuing operations from the electric utility decreased $1.2 million.

Corporate costs for the year ended December 31, 2005 increased $9.6 million after tax, compared to 2004. The increase is primarily due to the write-off of approximately $6.4 million, after-tax of certain capitalized project development costs and the expensing of other development costs, which are included in Administrative and general operating expenses on the accompanying consolidated statements of income. These costs were partially offset by allocating increased compensation and debt retirement costs down to the subsidiary level. In addition, the Company's subsidiary, Daksoft, Inc., recorded a $1.0 million pre-tax gain in 2004, on the sale of its campground reservation system.

Consolidated operating expenses for 2005 increased $359.8 million compared to 2004. Increased operating expenses reflect a $251.7 million increase in fuel and purchased power, a $52.2 million impairment charge at our power generation segment and a $33.3 million increase in administrative and general costs. Higher fuel and purchased power costs were primarily the result of the increased cost of crude oil marketed and the cost of sales of electricity and gas at Cheyenne Light, which was acquired during 2005. The increase in administrative and general costs was primarily the result of higher corporate development costs, including the write-off of previously capitalized development costs, higher legal and professional fees resulting from ongoing litigation, the additional administrative and general costs of Cheyenne Light, and higher compensation costs.

2004 Compared to 2003

Consolidated income from continuing operations for 2004 was $61.2 million, compared to $62.3 million in 2003, or $1.86 per share in 2004, compared to $2.01 per share in 2003. Loss from discontinued operations was $(3.2) million or $(0.10) per share in 2004, compared to income of $4.1 million or $0.13 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 $4.8 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 partially offset by lower interest expense.

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.

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

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2004 and 2003 information has been revised to remove information related to operations that were discontinued.

Retail Services Group

Electric Utility

	2005	2004	2003
		(in thousands)	
Revenue	$ 189,005	$ 173,745	$ 171,019
Operating expenses	152,961	129,936	119,920
Operating income	$ 36,044	$ 43,809	$ 51,099
Income from continuing operations and net income	$ 18,005	$ 19,209	$ 24,089

The following table provides certain electric utility operating statistics:

Electric Revenue (in thousands)					
Customer Base	2005	Percentage Change	2004	Percentage Change	2003
Commercial	$ 49,185	5%	$ 46,791	(2)%	$ 47,777
Residential	39,348	8	36,536	(3)	37,716
Industrial	19,982	1	19,796	1	19,589
Municipal sales	2,268	3	2,200	5	2,102
Contract wholesale	23,384	3	22,720	6	21,451
Wholesale off-system	47,647	25	38,228	13	33,743
Total electric sales	181,814	9	166,271	2	162,378
Other revenue	7,191	(4)	7,474	(14)	8,641
Total revenue	$ 189,005	9%	$ 173,745	2%	$ 171,019

Megawatt Hours Sold					
Customer Base	2005	Percentage Change	2004	Percentage Change	2003
Commercial	655,076	4%	627,326	(2)%	641,779
Residential	480,053	7	447,166	(3)	463,290
Industrial	417,628	3	406,209	—	404,341
Municipal sales	30,084	4	28,934	5	27,426
Contract wholesale	619,369	1	614,700	5	614,888
Wholesale off-system	869,161	(6)	926,461	15	773,801
Total electric sales	3,071,371	1%	3,050,796	4%	2,925,525

We established a new summer peak load of 401 megawatts in July 2005 and a new winter peak load of 356 megawatts in December 2005. We own 435 megawatts of electric utility generating capacity and purchase an additional 50 megawatts under a long-term agreement expiring in 2023.

Resources	2005	Percentage Change	2004	Percentage Change	2003
Megawatt-hours generated:					
Coal	1,728,823	(1)%	1,753,693	(3)%	1,806,444
Gas	37,239	34	27,825	(82)	156,703
	1,766,062	(1)	1,781,518	(9)	1,963,147
Megawatt-hours purchased	1,399,212	3	1,361,409	30	1,048,076
Total resources	3,165,274	1%	3,142,927	4%	3,011,223

	2005	2004	2003
Heating and cooling degree days			
Actual			
Heating degree days	6,488	6,553	7,065
Cooling degree days	830	522	891
Variance from normal			
Heating degree days	(10)%	(9)%	(2)%
Cooling degree days	39%	(13)%	49%

2005 Compared to 2004

Electric utility revenues increased 9 percent for the year ended December 31, 2005 compared to the same period in the prior year. Firm commercial, residential and contract wholesale sales increased 5 percent, 8 percent and 3 percent, respectively. Cooling degree days for the year were 59 percent higher than 2004 and heating degree days were 1 percent lower than 2004. Wholesale off-system sales increased 25 percent due to a 33 percent increase in average price received partially offset by a 6 percent decrease in megawatt-hours sold.

Electric operating expenses increased 18 percent for the year ended December 31, 2005, compared to the prior year. Higher operating expenses were primarily the result of an $18.5 million increase in fuel and purchased power costs. The increase in fuel and purchased power was due to a $16.9 million increase in purchased power, which includes $2.8 million of additional purchase power costs to cover the outage of Neil Simpson II, as well as a 31 percent increase in average price per megawatt-hour, and a 3 percent increase in megawatt-hours purchased. Fuel costs increased $1.6 million due to a 12 percent increase in average cost, partially offset by a 1 percent decrease in megawatt-hours generated. Megawatt-hours produced through coal-fired generation decreased while higher cost gas generation was utilized in 2005. Purchased power and gas generation were utilized for firm load demand and peaking needs due to unscheduled plant outages and warmer weather. The increase in operating expense was also affected by increased power marketing legal expense, compensation costs and corporate allocations, partially offset by lower maintenance costs due to scheduled and unscheduled plant maintenance in 2004.

Income from continuing operations decreased $1.2 million primarily due to increased fuel and purchased power costs, legal expense, compensation costs and corporate allocations, partially offset by increased revenues, lower maintenance costs, lower interest expense due to the pay down of debt, and a $1.9 million benefit from a deferred tax adjustment.

2004 Compared to 2003

Electric revenue increased 2 percent in 2004 compared to 2003, primarily due to a 13 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.

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 15 percent increase in wholesale off-system megawatt-hours accounted for a $4.5 million increase in revenues. Cooling degree days were 41 percent lower than 2003 and heating degree days were 7 percent lower than 2003.

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.

Electric and Gas Utility

	January 21, 2005 to December 31, 2005	
	(in thousands)	
Revenue	$	110,875
Operating expenses		107,822
Operating income	$	3,053
Income from continuing operations and net income	$	2,114

The following tables provide certain operating statistics for the Electric and Gas Utility Segment:

	Electric Revenue (in thousands)	
Customer Base	January 21, 2005 to December 31, 2005	
Commercial	$	39,841
Residential		24,910
Industrial		8,901
Municipal sales		607
Total electric sales		74,259
Other revenue		38
Total revenue	$	74,297

Resources	January 21, 2005 to December 31, 2005
Megawatt-hours purchased	919,388

Gas Revenue
(in thousands)

Customer Base		January 21, 2005 to December 31, 2005
Commercial	$	10,531
Residential		20,020
Industrial		5,352
Total gas sales		35,903
Other revenue		675
Total revenue	$	36,578

Resources	January 21, 2005 to December 31, 2005
Dekatherms purchased	4,031,463

	January 21, 2005 to December 31, 2005
Electric sales - MWh	889,210
Gas sales - Dth	4,062,590
Gas transport - Dth	8,286,338

On April 18, 2005, applications were filed with the Wyoming Public Service Commission (WPSC) to increase the base rates for retail electric and natural gas service effective January 1, 2006. The applications requested a 3.94 percent and 5.62 percent increase in electric and gas revenues, respectively. On October 3, 2005, the WPSC entered a bench order approving a stipulation and agreement with the Wyoming Office of Consumer Advocate which will result in an annual revenue increase of approximately $4.8 million beginning in 2006. The rates were effective January 1, 2006 and represent increases of 3.65 percent and 5.11 percent in electric and gas revenues, respectively. We expect additional costs in 2006 related to allocated corporate costs to total approximately $2.7 million. In addition, we filed an out-of-period gas cost adjustment reflecting higher natural gas costs, which was approved by regulators and became effective February 1, 2006.

Wholesale Energy Group

Power Generation

Our power generation segment produced the following results:

	2005	2004	2003
		(in thousands)	
Revenue	$ 158,399	$ 158,037	$ 284,567**
Operating expenses	160,553*	110,103	225,674**
Operating (loss) income	$ (2,154)	$ 47,934	$ 58,893
(Loss) income from continuing operations	$ (12,524)	$ 15,562	$ 22,429

* Operating expenses in 2005 includes a $52.2 million impairment of long-lived assets (see Note 13 of our Notes to Consolidated Financial Statements).

**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 12 and 13 of our Notes to Consolidated Financial Statements).

	2005	2004	2003
Independent Power Capacity:			
MWs of independent power capacity in service	1,000	964	962
Contracted fleet plant availability	96.8%	98.6%	96.0%

2005 Compared to 2004

Revenues for the year ended December 31, 2005 were flat compared to revenues in the same period in 2004. Increased revenues at our Las Vegas II facility and increased revenues from higher megawatts generated at our Gillette CT were offset by decreased revenues from Las Vegas I, due to a plant maintenance outage. In the twelve months of 2005, our Las Vegas II facility sold capacity and energy to Nevada Power Company under a long-term tolling arrangement, which became effective April 1, 2004, as opposed to selling power into the market on a merchant basis for the first three months of 2004, only when it was economic to do so.

Operating expenses for the year ended December 31, 2005 increased $50.5 million, due primarily to a $50.3 million impairment charge on the Las Vegas I plant, a $1.9 million impairment of goodwill relating to certain power fund investments, increased fuel costs at our Gillette CT, a $1.6 million charge related to a fuel contract termination and increased corporate allocations. The increase in operating expenses was partially offset by a reduction in fuel expense at the Las Vegas II facility, which incurred fuel costs in the first three months of 2004, before the new, long-term tolling arrangement took effect and lower fuel expense at Las Vegas I due to planned maintenance in the fourth quarter of 2005.

Income from continuing operations decreased $28.1 million, primarily due to the $32.7 million after-tax impact of the Las Vegas I impairment charge, a fuel contract termination charge and increased corporate allocations and deferred tax adjustments that lowered earnings by $2.8 million, partially offset by a $6.1 million after-tax increase in earnings from certain power fund investments.

Plant availability of our contracted fleet was affected by the planned maintenance at Las Vegas I and unplanned outages at Las Vegas II. Excluding Las Vegas facilities, the availability of the remainder of our gas-fired fleet was approximately 99 percent and availability of our Wygen I coal-fired plant exceeded 95 percent.

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 I 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.

Oil and Gas

Oil and gas operating results were as follows:

	2005	2004	2003
		(in thousands)	
Revenue	$ 87,549	$ 59,534	$ 46,977
Operating expenses	55,944	40,353	33,719
Operating income	$ 31,605	$ 19,181	$ 13,258
Income from continuing operations	$ 17,905	$ 12,200	$ 8,400

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

	2005	2004	2003
Barrels of oil sold	395,550	432,400	415,800
Mcf of natural gas sold	11,372,000	10,000,100	8,348,400
Mcf equivalent sales	13,745,300	12,594,600	10,843,400

The following is a summary of Lease Operating Expense ($/Mcfe) at December 31:

	2005	2004	2003
New Mexico	$ 1.07	$ 1.15	$ 1.41
All other properties	$ 0.82	$ 0.85	$ 0.75
Total LOE	$ 0.93	$ 0.97	$ 0.95

Lease operating expenses (LOE) at our New Mexico properties include approximately $0.65/Mcfe in 2005 and 2004, and $0.80/Mcfe in 2003 for gathering, compression and processing costs. In the East Blanco Field in New Mexico, we own and operate the gas gathering system, including associated compression and processing facilities.

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

	2005	2004	2003
Barrels of oil (in thousands)	6,835	5,239	5,389
MMcf of natural gas	128,573	141,983	124,062
Total in MMcf equivalents	169,583	173,417	156,396
Present value of estimated future net revenues before tax (in thousands)	$ 560,023	$ 394,446	$ 265,341

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 reflect year end pricing of:

	2005		2004		2003	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 61.04	$ 11.23	$ 43.45	$ 6.15	$ 32.52	$ 6.19
Year-end prices (average well-head)	$ 58.52	$ 9.06	$ 41.19	$ 5.55	$ 30.56	$ 4.63

2005 Compared to 2004

Revenues from oil and gas increased 47 percent for the year ended December 31, 2005 compared to the year ended December 31, 2004. Gas volumes sold increased 14 percent due to increased production from recently completed wells, and oil volumes sold decreased 9 percent primarily due to a normal decline in our mature Wyoming oil field and reduced enhanced oil recovery activities. Average natural gas price received, net of hedges and exclusive of gas liquids, for the year ended December 31, 2005 was $6.36/Mcf compared to $4.56/Mcf in the same period of 2004. Average oil price received, net of hedges, for the year ended December 31, 2005 was $35.99/bbl compared to $26.24/bbl in the same period of 2004.

Lease operating expense increased 5 percent primarily due to generally higher field service costs experienced industry-wide and the increase in number of producing wells as a result of the current drilling program. The LOE/MCFE for the year decreased 4 percent from $0.97/Mcfe in 2004 to $0.93/Mcfe in 2005 due to higher production rates and efficiencies realized in certain of our fields where significant production increases have been achieved. Depletion expense per Mcfe (excluding liquids) increased 60 percent over the prior year from $0.96/Mcfe in 2004 to $1.54/Mcfe in 2005. The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The increased rate is primarily a reflection of higher industry-wide drilling and completion costs that significantly increased our estimated future development costs in addition to lower than expected reserve estimates.

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 price received, net of hedges and exclusive of gas liquids, for the year ended December 31, 2004 was $4.56/Mcf compared to $3.92/Mcf in the same period of 2003. Average oil price received, net of hedges, for the year ended December 31, 2004 was $26.24/bbl compared to $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 10 percent from $0.87 per Mcfe to $0.96 per Mcfe.

Additional information on our Oil and Gas operations can be found in Note 25 to our Notes to Consolidated Financial Statements.

Energy Marketing and Transportation

Our energy marketing and transportation companies produced the following results:

	2005	2004	2003
		(in thousands)	
Revenue	$ 815,825	$ 662,110	$ 675,586
Operating expenses	792,542	643,929	663,435
Operating income	$ 23,283	$ 18,181	$ 12,151
Income from continuing operations	$ 16,359	$ 10,222	$ 6,725

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

	2005	2004	2003
Natural gas physical sales - MMbtus	1,427,400	1,226,600	897,850
Natural gas financial sales - MMbtus	709,200	514,500	344,050
Crude oil – barrels marketed	37,600	44,900	58,700
Crude oil – barrels transported	37,000	52,300	58,300

2005 Compared to 2004

Revenue increases were primarily due to a 48 percent increase in average price received from crude oil marketed, partially offset by decreased crude oil volumes marketed. In addition, gas marketing margins increased while oil transportation revenues decreased primarily due to suspension of shipments for routine regulatory required pressure testing of the Millennium pipeline system.

Income from continuing operations increased $6.1 million primarily due to higher margins and volumes at our gas marketing operation and higher margins from oil marketing operations and a positive foreign tax credit reserve adjustment of $1.3 million. These items were partially offset by a charge for a litigation settlement accrual of $2.6 million relating to a class action lawsuit, initiated in 2003, that alleged false reporting of natural gas price and volume information and lower oil transportation earnings. Gas marketing unrealized mark-to-market gains for the year ended December 31, 2005 were $6.2 million higher than unrealized mark-to-market losses for the same period in 2004. We expect approximately $2.0 million of the unrealized mark-to-market gain to reverse in 2006. In addition, realized gross margins from natural gas and crude oil marketing increased $6.6 million.

On January 5, 2006, we announced that we had entered into a definitive agreement to sell the operating assets of our crude oil marketing and transportation business. This transaction was completed March 1, 2006. Beginning with the first quarter of 2006, the operations of this business will be classified as discontinued operations. Crude oil marketing revenues and cost of sales are presented on a gross basis in accordance with accounting standards generally accepted in the United States. Accordingly, the classification to discontinued operations will have a significant effect on our consolidated presented revenues and cost of sales. For the years ended December 31, 2005, 2004 and 2003, revenues from crude oil marketing and transportation were $778.1 million, $636.6 million and $652.7 million; and related cost of sales were $765.2 million, $620.3 million and $638.9 million, respectively.

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 negatively impacted by the $3.0 million CFTC settlement.

Coal Mining

Coal mining results were as follows:

	2005	2004	2003
		(in thousands)	
Revenue	$ 34,277	$ 31,967	$ 34,777
Operating expenses	26,385	23,513	26,002
Operating income	$ 7,892	$ 8,454	$ 8,775
Income from continuing operations	$ 6,947	$ 7,463	$ 8,289

The following is a summary of coal sales quantities:

(Thousands of tons)	2005	2004	2003
Tons of coal sold	4,701	4,780	4,812
Coal reserves	290,000	294,000	263,000

2005 Compared to 2004

Revenue from our Coal mining segment increased 7 percent for the year ended December 31, 2005 compared to 2004. In 2004, the Company reached a tax settlement with the Wyoming Department of Revenue which resulted in a $1.7 million reduction in revenues and a corresponding reduction in mineral taxes in September, 2004. The Company also recorded an additional $0.4 million decrease to mineral taxes and $0.5 million decrease to interest expense related to the settlement. Revenues were also impacted by a 2 percent decrease in tons of coal sold, primarily due to unscheduled plant outages at the Neil Simpson II and Wyodak power plants, offset by higher average prices.

Operating expenses increased 12 percent for the year ended December 31, 2005 primarily due to the reduction of 2004 mineral tax expense due to the recording of the 2004 tax settlement and increased transportation and overburden removal costs and compensation expense and corporate allocations, partially offset by decreased depletion expense, due to lower depletion rates.

Income from continuing operations decreased 7 percent primarily due to increased transportation and overburden removal costs and compensation expense and corporate allocations, partially offset by the decrease in depletion expense. In addition, 2004 results were affected by a $0.4 million benefit from an income tax reserve adjustment and a $0.6 million after-tax benefit from the Wyoming tax settlement.

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 I plant.

In 2004, the Company recorded a $1.7 million reduction in revenues and a corresponding reduction in mineral taxes as a result of a tax settlement with the Wyoming Department of Revenue. 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 and a $0.4 million benefit from an income tax reserve adjustment.

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.

The following discussion of our critical accounting policies should be read in conjunction with Note 1, “Business Description and Summary of Significant Accounting Policies” of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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.

During the third quarter of 2005, in accordance with our accounting policies, we evaluated for impairment the long-lived asset carrying values of our Las Vegas I power plant. In measuring the fair value of the Las Vegas I power plant and the resulting impairment charge of approximately $50.3 million pre-tax, 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 $0.3 million higher. If the discount rate would have been 1 percent lower, the impairment charge would have been approximately $0.3 million lower.

During the fourth quarter of 2005, we wrote off goodwill of approximately $1.9 million, net of accumulated amortization of $0.3 million, related to partnership “equity flips” at certain power fund investments. As these funds follow accounting policies which require their plant investments to be carried at fair value, our goodwill represented an excess investment cost in the funds that was only supported by the value of the potential increased partnership equity. When the “equity flip” was triggered by performance thresholds being met, the value of the additional partnership interest was recognized and our related goodwill impaired.

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 “(Loss) income from discontinued operations, net of income taxes” on the 2004 Consolidated Statement of Income.

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. Utilization of other possible cash flow scenarios and/or different weighting of those that were accepted 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.

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, 2005, 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 annually 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.

Oil and Natural Gas Reserve Estimates

Estimates of our proved oil and natural gas reserves are based on the quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any oil and natural gas reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Despite the inherent imprecision in these engineering estimates, estimates of our oil and natural gas reserves are used throughout our financial statements. For example, as we use the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporates the estimated units-of-production attributable to the estimates of proved reserves. Our oil and gas properties are also subject to a "ceiling" limitation based in large part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

The estimates of our proved oil and natural gas reserves have been reviewed by independent petroleum engineers.

Risk Management Activities

In addition to the information provided below, see Note 2 "Risk Management Activities," of our Notes to Consolidated Financial Statements.

<u>Derivatives</u>

We account for derivative financial instruments in accordance with SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). Accounting for derivatives under SFAS 133 requires the recognition of all derivative instruments as either assets or liabilities on the balance sheet and that they be measured at fair value.

We currently use derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. 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. Our marketing and trading operations utilize various physical and financial contracts to effectively manage our marketing and trading portfolios.

Fair values of derivative instruments and energy trading contracts are based on actively quoted market prices or other external source pricing information, where possible. If external 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 19 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 Plans

We account for our defined benefit pension plans 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, 2005, 2004 and 2003, we recorded non-cash expense related to our pension plans of approximately $2.9 million, $2.6 million, and $3.2 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 $6.5 million to $59.3 million for the plan fiscal year ended September 30, 2005. Plan assets earned $8.9 million in 2005. Plan assets increased $4.0 million to $52.8 million as of September 30, 2004. Plan assets earned $6.3 million in 2004. In the recently completed actuarial valuation, for determining our 2006 pension expense, we decreased the assumed rate of return on plan assets from 9.0 percent to 8.5 percent. This change is expected to increase pension costs in 2006 and beyond by approximately $0.3 million per year. The expected long-term rate of return on plan assets was 9.0 percent, 9.5 percent and 10.0 percent for the 2005, 2004 and 2003 plan years, respectively.

The 9.0 percent assumed rate of return for the 2005 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%	9.5%	8.5%
Fixed Income	5%	6.0%	0.3%
Cash	5%	4.0%	0.2%
	100%		9.0%

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

The expected long-term rate of return for equity investments was 9.5 percent and 10.0 percent for the 2005 and 2004 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns for the S&P 500 Index, which were, at December 31, 2005, 11.8 percent, 12.5 percent, 10.1 percent and 10.3 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on 10-year treasury bonds of 7.0 percent from 1962 to 2005 and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below fixed income investments.

The discount rate we utilize for determining benefit obligations and benefit cost is based on high grade bond rates. The discount rate was 6.0 percent for the 2005 and 2004 pension cost determination, a decrease from 6.75 percent in 2003. In the recently completed actuarial valuation, for determining our 2006 pension expense, we decreased the discount rate to 5.75 percent. A 0.25 percent decrease in the discount rate would cause annual pension expense to increase by approximately $0.3 million.

During the first quarter of 2006, a contribution of $1.2 million was made to the Cheyenne Light, Fuel & Power Company Pension Plan. Based on our recently completed plan forecasts, we estimate that we will not be required to make any additional cash contributions to our pension plans in the 2006 fiscal year.

Actual pension expense and contributions required will depend on future investment performance, changes in future discount rates 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 key executives. The plans are nonqualified defined benefit plans accounted for in accordance with SFAS 87. Expenses recognized under the plans were $2.0 million in 2005, $2.3 million in 2004, and $1.7 million in 2003. The plans are unfunded. The actuarial assumptions used for our non-qualified pension plans are the same as those used for our qualified plan, except for the assumptions for rate of increases in compensation levels.

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 plans. 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, 2005, 2004 and 2003, we recorded other postretirement benefit expense of approximately $1.8 million, $1.5 million and $1.2 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, 2005 Accumulated Postretirement Benefit Obligation	Impact on 2005 Service and Interest Cost
	(in thousands)	
Increase 1%	$ 2,966	$ 407
Decrease 1%	$ (2,307)	$ (311)

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, the healthcare cost trend rate used by the actuaries to determine our other postretirement benefit expense for 2005 expense determination was 11 percent in 2005, decreasing gradually to 5 percent in 2011. The healthcare cost trend rate assumption for 2004 expense determination was 12 percent in 2004, decreasing gradually to 5 percent in 2011. 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.

Contingencies

When it is probable that an environmental, tax or other legal liability has been incurred, a loss is recognized when the amount of the loss can be reasonably estimated. Estimates of the probability and the amount of loss are made based on currently available facts. Accounting for contingencies requires significant judgment regarding the estimated probabilities and ranges of exposure to potential liability. Our assessment of our exposure to contingencies could change to the extent there are additional future developments, or as more information becomes available. If actual obligations incurred are different from our estimates, the recognition of the actual amounts could have a material impact on our financial position and results of operations.

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 realization 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, 2005 and 2004 is presented in the following table:

Financial Position Summary	2005	2004	Percentage Change
	(in thousands)		
Cash and cash equivalents	$ 34,198	$ 64,506	(47.0)%
Short-term debt	66,771	40,166	66.2%
Long-term debt	670,193	733,581	(8.6)%
Stockholders' equity	738,879	735,765	0.4%
Ratios			
Long-term debt ratio	47.6%	49.9%	(4.6)%
Total debt ratio	49.9%	51.3%	(2.7)%

Our dividend payout ratio at December 31, 2005 was approximately 128 percent which is higher than levels over the past 5 years. Based on current expectations for 2006, we expect payout ratios for 2006 to be in the range of 59 percent to 63 percent.

In 2006, 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

2005

In 2005, 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.

Cash flows from operations increased $37.8 million from the prior year amount, as a $24.4 million decrease in net income was more than offset by the following:

- An $85.1 million increase related to non-cash charges for the impairment of our Las Vegas I power plant and goodwill at certain power fund investments of $52.2 million, higher depreciation, depletion and amortization of $15.3 million, the write-off of capitalized project development costs of $5.0 million, increases related to employee benefit plans of $7.5 million and increases of regulatory assets of $5.1 million, primarily related to the Cheyenne Light acquisition.

- A $31.8 million increase in the change in current operating assets and liabilities. This is primarily driven by $36.4 million less being spent on material, supplies and fuel during the year. Fluctuations in our material, supplies and fuel balances are largely the result of natural gas inventory held by our natural gas marketing company in the form of storage agreements.

- A $36.7 million decrease from changes in deferred income taxes, largely the result of decreases in our net deferred tax liability primarily due to impairment charges, net operating losses, depreciation and other plant related differences, and employee benefit plans, partially offset by increases from mining development and oil exploration costs.

We had cash outflows from investing activities of $109.7 million, primarily for construction expenditures for Wygen II, acquisitions and development drilling of oil and gas properties and property, plant and equipment additions in the normal course of business and the $65.1 million cash payment related to the acquisition of Cheyenne Light, partially offset by $103.0 million cash received for the sale of Black Hills FiberSystems.

We had cash outflows from financing activities of $95.5 million, primarily due to the repayment of $81.5 million of project level debt at our Fountain Valley facility and the payment of cash dividends partially offset by an increase in short term borrowings.

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 $34.1 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 increase in the change in deferred taxes, a $31.5 million increase in the change in current operating assets and liabilities primarily due to increases in accounts payable and decreases in prepaid income taxes, offset by increased inventory, and a $7.5 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 $152.4 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 repaid $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.
- On 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.

Dividends

Dividends paid on our common stock totaled $1.28 per share in 2005. This reflects an increase in comparison to prior years' dividend levels of $1.24 per share in 2004 and $1.20 per share in 2003. All dividends were paid out of operating cash flows. Our three-year annualized dividend growth rate was 3.3 percent. In January 2006, our board of directors increased the quarterly dividend 3.1 percent to $0.33 cents per share. If this dividend is maintained during 2006, it will be equivalent to $1.32 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 our credit facilities and our future business prospects.

Liquidity

Our principal sources of short-term liquidity include our cash on hand, our revolving credit facility and cash provided by operations. As of December 31, 2005 we had approximately $34.2 million of cash unrestricted for operations and $400 million of credit through a revolving bank facility. Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At December 31, 2005, we had $55.0 million of bank borrowings outstanding and $60.7 million of letters of credit issued under this facility, with a remaining borrowing capacity of $284.3 million. Approximately $8.5 million of the cash balance at December 31, 2005 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company.

On May 5, 2005, we entered into a new $400 million revolving credit facility with ABN AMRO as Administrative Agent, Union Bank of California and US Bank as Co-Syndication Agents, Bank of America and Harris Nesbitt as Co-Documentation Agents, and other syndication participants. The new facility has a five year term, expiring May 4, 2010. The facility contains a provision which allows the facility size to be increased by up to an additional $100 million through the addition of new lenders, or through increased commitments from existing lenders, but only with the consent of such lenders. The cost of borrowings or letters of credit issued under the new facility is determined based on our credit ratings; at our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70.0 basis points over the LIBOR (which equates to a 5.09 percent one-month borrowing rate as of December 31, 2005). In conjunction with entering into the new revolving credit facility, we terminated our $125 million revolving bank facility due May 12, 2005 and our $225 million facility due August 20, 2006.

The above credit facility includes customary affirmative and negative covenants such as limitations on the creation of new indebtedness and on certain liens, restrictions on certain transactions and maintenance of the following financial covenants:

- a consolidated net worth in an amount of not less than the sum of $625 million and 50 percent of our aggregate consolidated net income beginning January 1, 2005;
- a recourse leverage ratio not to exceed 0.65 to 1.00;
- and a fixed charge coverage ratio of not less than 2.5 to 1.0.

A default under the credit facility may be triggered by events such as a failure to comply with financial covenants or certain other covenants under the credit facility, a failure to make payments when due or a failure to make payments when due in respect of, or a failure to perform obligations relating to, debt obligations of $20 million or more. A default under the credit facility would permit the participating banks to restrict the Company's ability to further access the credit facility for loans or new letters of credit, require the immediate repayment of any outstanding loans with interest and require the cash collateralization of outstanding letter of credit obligations.

The credit facility prohibits the Company from paying cash dividends unless no default or no event of default exists prior to, or would result after, giving effect to such action.

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 the payment of all principal and interest outstanding. As of December 31, 2005, we were in compliance with the above covenants.

Our consolidated net worth was $738.9 million at December 31, 2005, which was approximately $97.2 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, 2005 was 47.6 percent, our total debt leverage ratio was 49.9 percent and our recourse leverage ratio was approximately 48.8 percent.

On January 21, 2005, we purchased Cheyenne Light for approximately $90.7 million, including the assumption of $24.6 million of Cheyenne Light 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 to the above lines of credit, at December 31, 2005, Enserco Energy (Enserco) has a $200.0 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 November 30, 2006. The Company has made a $3.0 million guarantee to the lender associated with the line of credit. At December 31, 2005 there were outstanding letters of credit issued under the facility of $165.1 million, with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. (BHER), our oil marketing unit, has maintained an uncommitted, discretionary credit facility. The facility allowed BHER to elect from $25.0 million up to $60.0 million of available credit via notification to the bank at the beginning of each calendar quarter. The line of credit provided credit support for the purchases of crude oil by BHER. At December 31, 2005, BHER had elected to have $50.0 million of available credit and had letters of credit outstanding of $48.5 million. At December 31, 2005, BHER was compliant with, or issued waivers for, the debt covenants related to this facility. On March 1, 2006, in conjunction with the sale of the assets of BHER, the facility was terminated.

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, 2005:

	Payments Due by Period (in thousands)				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt [(a)(b)(c)]	$ 680,485	$ 11,771	$ 252,521	$ 52,825	$ 363,368
Unconditional purchase obligations [(d)]	303,308	90,152	102,871	20,997	89,288
Operating lease obligations [(e)]	17,496	1,810	4,209	1,435	10,042
Capital leases [(f)]	101	16	36	42	7
Other long-term obligations [(g)]	24,958	—	—	—	24,958
Credit facilities	55,000	55,000	—	—	—
Total contractual cash obligations	$ 1,081,348	$ 158,749	$ 359,637	$ 75,299	$ 487,663

(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) In addition the following amounts are required for interest payments on long-term debt over the next five years: $42.7 million in 2006, $38.6 million in 2007, $31.6 million in 2008, $28.2 million in 2009 and $26.1 million in 2010.

(c) We expect to refinance maturities on the project financing floating rate debt with project level or corporate level intermediate or long-term debt.

(d) Unconditional purchase obligations include the capacity costs associated with our purchase power agreement with PacifiCorp, the cost of purchased power for Cheyenne Light under our all-requirements contract with PSCo, and certain transmission, 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 based on costs incurred during 2005 and price assumptions using existing prices at December 31, 2005. Our transmission obligations are based on filed tariffs as of December 31, 2005. Actual future costs under the variable rate contracts may differ materially from the estimates used in the above table.

(e) Includes operating leases associated with several office buildings and land leases associated with the Arapahoe, Valmont, Harbor and Ontario power plants.

(f) Represents a lease on office equipment.

(g) Includes our asset retirement obligations associated with our oil and gas, coal mining and electric and gas utility 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, 2005, we had guarantees totaling $162.5 million in place. Of the $162.5 million, $137.2 million was related to guarantees associated with subsidiaries' debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets, $19.9 million was related to performance obligations under subsidiary contracts and $5.4 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 21 of our Notes to Consolidated Financial Statements.

As of December 31, 2005, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2005	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	2006
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2006
Guarantee of interest rate swap transaction with Union Bank of California	930	2006
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	250	2006
Guarantee obligations under the Wygen I Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	26,213	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	5,374	Ongoing
	$ 162,535	

Credit Ratings

As of February 28, 2006, 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. In June 2005, Moody's revised the outlook on our credit ratings from negative to stable. In February 2006, Standard and Poor's revised the credit rating outlook from negative outlook to CreditWatch negative due primarily to uncertainties surrounding the proposed combination with Northwestern Corporation. 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 annual interest expense by approximately $0.8 million pre-tax based on December 31, 2005 balances.

Capital Requirements

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

	2005	2004	2003
		(in thousands)	
Property additions and acquisition costs:			
Wholesale energy –			
Coal mining	$ 6,517	$ 3,183	$ 8,203
Oil and gas	71,799	53,891	43,448
Energy marketing and transportation	2,429	622	822
Power generation	6,095	6,043	28,798
Retail services –			
Electric utility	18,162	13,347	25,427
Electric and gas utility	95,654*	—	—
Communications	5,110	8,101	7,780
Corporate	3,090	5,787	2,213
Common and preferred stock dividends	42,212	40,531	37,283
Maturities/redemptions of long-term debt	94,171	155,021	139,310
	$ 345,239	$ 286,526	$ 293,284

*Includes $65.1 million acquisition cost of Cheyenne Light and $23.8 million for Wygen II construction.

Our capital additions for 2005 were $203.7 million. The capital expenditures were primarily for the acquisition cost of Cheyenne Light, construction of the Wygen II power plant, development drilling of oil and gas properties and maintenance capital.

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.

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

	2006	2007	2008
		(in thousands)	
Wholesale energy:			
Coal mining	$ 10,150	$ 6,610	$ 8,840
Oil and gas**	72,030	49,680	52,220
Energy marketing and transportation	470	590	590
Power generation	5,100	7,860	12,410
Retail services:			
Electric utility	29,390	34,320	19,050
Electric and gas utility*	127,166	43,667	8,480
Corporate	—	—	—
Unspecified development capital	—	46,380	104,870
	$ 244,306	$ 189,107	$ 206,460

* Regulated electric and gas utility capital requirements include approximately $112.1 million and $33.2 million for the development of the Wygen II coal-fired plant in 2006 and 2007, respectively.

** Forecasted capital requirements do not include the acquisition or future development costs of the Koch properties that we entered into a definitive agreement to acquire during March 2006.

We continue to actively evaluate potential future acquisitions and other growth opportunities in accordance with our disclosed business strategy. We are not obligated to a project until a definitive agreement is entered into and cannot guarantee we will be successful on any potential projects. Future projects are dependent upon the availability of economic opportunities and, as a result, actual expenditures may vary significantly from forecasted estimates.

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 long position with crude oil and natural gas reserves and production, and fuel procurement for our gas fired generation assets;
- 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; and
- foreign currency exchange risk associated with our natural gas marketing business transacted in Canadian dollars.

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, currency exchange 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 and industrial customers 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 and trading 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 calculations are also used to quantify the potential loss in fair value of the entire 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 standardized methodology or widely accepted 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.

In addition to VaR analysis, risk management daily activities include scrutinizing positions, assessing changes in daily mark-to-market, simulating price movements, and other non-statistical risk management techniques that do not include VaR. In 2005, our three-day, 99 percent loss level VaR was always estimated to be below $4.0 million. At year-end 2005 and 2004, our estimate of three-day, 99 percent loss level VaR was approximately $2.5 million and $1.7 million, respectively.

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, 2005 and 2004, 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, 2005 (in thousands):

Total fair value of natural gas marketing marked-to-market at December 31, 2004	$	(930) [a]
Net cash settled during the year on positions that existed at December 31, 2004		600
Unrealized gain on new positions entered during the year and still existing at December 31, 2005		5,868
Realized gain on positions that existed at December 31, 2004 and were settled during year		341
Unrealized loss on positions that existed at December 31, 2004 and still exist at December 31, 2005.		—
Total fair value of natural gas marketing positions marked-to-market at December 31, 2005	$	5,879 [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, 2005		December 31, 2004
Net derivative assets/(liabilities)	$	(764)	$	8,082
Fair value adjustment recorded in material, supplies and fuel		6,643		(9,012)
	$	5,879	$	(930)

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 circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 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, 2005, we had a mark to fair value unrealized gain of $5.9 million for our natural gas marketing activities. Of this amount, $6.2 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	2006	2007 and Thereafter	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ (2,128)	$ 1,847	$ (281)
Prices provided by other external sources	8,346	(2,186)	6,160
Modeled	—	—	—
Total	$ 6,218	$ (339)	$ 5,879

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. In accordance with generally accepted accounting principles and industry practice, the Company includes a “Liquidity Reserve” in its GAAP marked-to-market fair value. This “Liquidity Reserve” accounts for the estimated impact of the bid/ask spread in a liquidation scenario under which the Company is forced to liquidate its forward book on the balance sheet date.

Fair value of our natural gas marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 5,879
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	13,901
Fair value of all forward positions (non-GAAP)	19,780
“Liquidity reserve” included in GAAP marked-to-market fair value	1,244
Fair value of all forward positions excluding “Liquidity reserve” (non-GAAP)	$ 21,024

Activities Other than Trading

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our reserves are natural "long" positions, or unhedged open positions, and 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 from an enterprise-wide risk 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, 2005 and 2004 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, 2006 and 2007 natural gas and crude oil production. The hedge agreements in place are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (mmbtu/day)	Price
San Juan El Paso	11/04/2004	Swap	11/05 – 03/06	2,500	$ 7.08
San Juan El Paso	04/04/2005	Swap	11/05 – 03/06	2,500	$ 7.77
San Juan El Paso	07/12/2005	Swap	11/05 – 03/06	5,000	$ 8.03
San Juan El Paso	08/10/2005	Swap	11/05 – 03/06	2,500	$ 8.90
San Juan El Paso	07/12/2005	Swap	04/06 – 10/06	5,000	$ 7.00
San Juan El Paso	12/14/2005	Swap	11/06 – 03/07	5,000	$ 10.25

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (barrels/month)	Price
NYMEX	10/06/2004	Swap	Calendar 2006	10,000	$ 41.00
NYMEX	12/14/2005	Put	Calendar 2006	5,000	$ 55.00
NYMEX	01/12/2006	Put	02/06 – 12/06	5,000	$ 65.50
NYMEX	07/29/2005	Swap	Calendar 2007	5,000	$ 61.00
NYMEX	08/04/2005	Swap	Calendar 2007	5,000	$ 62.00
NYMEX	01/04/2006	Swap	Calendar 2007	5,000	$ 65.00

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 certain gas-fired generation assets under long-term contracts 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, 2005, we had $163 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 10 years. Further details of the swap agreements are set forth in Note 2 of our Notes to Consolidated Financial Statements.

On December 31, 2005 and 2004, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2005	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 (Loss)	Pre-tax (Loss)
Swaps on project financing	$ 163,000	4.43%	10.00	$ 13	$ —	$ 76	$ 230	$ (249)	$ (44)
December 31, 2004									
Swaps on project financing	$ 113,000	4.22%	1.75	$ 60	$ —	$ 1,226	$ 200	$ (1,366)	$ —

We anticipate a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2006. Based on December 31, 2005 market interest rates, less than $0.1 million will be realized as additional interest expense during 2006. Estimated and realized amounts will likely change during 2006 as market interest rates change.

At December 31, 2005, we had $292.5 million of outstanding, variable-rate debt of which $179.5 million was not offset with interest rate swap transactions that effectively convert a portion of the debt to a fixed rate. A 100 basis point increase in interest rates would cause interest expense to increase $2.2 million in 2006.

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):

	2006	2007	2008	2009	2010	Thereafter	Total
Cash equivalents							
Fixed rate	$ 34,198	$ —	$ —	$ —	$ —	$ —	$ 34,198
Long-term debt							
Fixed rate	$ 3,065	$ 2,249	$ 2,262	$ 2,278	$ 32,296	$ 345,829	$ 387,979
Average interest rate	8.45%	9.38%	9.41%	9.44%	8.16%	7.21%	7.33%
Variable rate [(a)]	$ 8,706	$ 113,468	$ 130,264	$ 2,000	$ 18,213	$ 19,855	$ 292,506
Average interest rate	6.34%	6.29%	4.87%	6.54%	6.54%	3.69%	5.50%
Total long-term debt	$ 11,771	$ 115,717	$ 132,526	$ 4,278	$ 50,509	$ 365,684	$ 680,485
Average interest rate	6.89%	6.35%	4.94%	8.08%	7.57%	7.02%	6.55%

(a) Approximately 39 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 4.43 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 other 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 segments) was concentrated with investment grade companies. Approximately 82 percent of our credit exposure was with investment grade companies. For the 18 percent credit exposure with non-investment grade rated counterparties, approximately 79 percent of this exposure was supported through letters of credit, prepayments, parental guarantees or 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, 2005 and 2004, we had outstanding forward exchange contracts to sell approximately $29.0 million and $38.0 million Canadian dollars, respectively. At December 31, 2005 and 2004, we also had outstanding forward exchange contracts to purchase approximately $88.0 million and $10.8 million Canadian dollars, respectively. These contracts had a fair value of $(1.0) million at December 31, 2005 and 2004, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2005 settle by May 2006.

New Accounting Pronouncements

See Note 1 of our Notes to Consolidated Financial Statements for information on new accounting standards adopted in 2005 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.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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, 2005, 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, 2005.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 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, 2005, 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, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2005, of the Corporation, and our report dated March 13, 2006, expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the adoption of Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities*, effective January 1, 2003 and Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities*, effective December 31, 2003.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 13, 2006

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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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, 2005, 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 13, 2006, 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 2 to the consolidated financial statements, effective January 1, 2003, the Corporation adopted Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities.* Also, 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*.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 13, 2006

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2005	2004	2003
	(in thousands, except per share amounts)		
Revenues:			
Operating revenues	$ 1,391,644	$ 1,082,115	$ 1,098,040
Contract termination revenue	—	—	114,000
	1,391,644	1,082,115	1,212,040
Operating expenses:			
Fuel and purchased power	954,968	703,261	718,450
Operations and maintenance	78,701	78,586	77,965
Administrative and general	95,751	62,439	67,205
Depreciation, depletion and amortization	89,306	74,040	66,523
Taxes, other than income taxes	34,807	27,536	28,413
Impairment of long-lived assets (Notes 1 and 13)	52,175	—	117,207
	1,305,708	945,862	1,075,763
Operating income	85,936	136,253	136,277
Other income (expense):			
Interest expense	(48,634)	(48,094)	(48,765)
Interest income	1,856	1,758	1,076
Other expense	(290)	(484)	(539)
Other income	1,143	1,160	1,209
	(45,925)	(45,660)	(47,019)
Income from continuing operations before minority interest, income taxes and change in accounting principle	40,011	90,593	89,258
Equity in earnings of unconsolidated subsidiaries	14,325	(386)	5,747
Minority interest	(277)	(186)	—
Income taxes	(18,299)	(28,831)	(32,734)
Income from continuing operations before changes in accounting principles	35,760	61,190	62,271
(Loss) income from discontinued operations, net of income taxes	(2,340)	(3,217)	4,146
Changes in accounting principles, net of income taxes	—	—	(5,195)
Net income	33,420	57,973	61,222
Preferred stock dividends	(159)	(321)	(258)
Net income available for common stock	$ 33,261	$ 57,652	$ 60,964
Earnings (loss) per share of common stock:			
Basic-			
Continuing operations	$ 1.09	$ 1.88	$ 2.03
Discontinued operations	(0.07)	(0.10)	0.14
Changes in accounting principles	—	—	(0.17)
Total	$ 1.02	$ 1.78	$ 2.00
Diluted-			
Continuing operations	$ 1.07	$ 1.86	$ 2.01
Discontinued operations	(0.07)	(0.10)	0.13
Changes in accounting principles	—	—	(0.17)
Total	$ 1.00	$ 1.76	$ 1.97
Weighted average common shares outstanding:			
Basic	32,765	32,387	30,496
Diluted	33,288	32,912	31,015

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2005	2004
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 34,198	$ 64,506
Restricted cash	—	3,069
Accounts receivable (net of allowance for doubtful accounts of $4,685 and $4,196, respectively)	352,445	251,945
Materials, supplies and fuel	126,753	88,475
Derivative assets	20,681	23,199
Deferred income taxes	—	2,697
Other current assets	7,891	11,098
Assets of discontinued operations	—	117,861
	541,968	562,850
Investments	27,558	24,436
Property, plant and equipment	1,958,059	1,805,768
Less accumulated depreciation and depletion	(522,661)	(468,840)
	1,435,398	1,336,928
Other assets:		
Goodwill	31,536	30,144
Intangible assets, net	27,826	36,688
Derivative assets	1,898	315
Other	53,776	38,206
	115,036	105,353
	$ 2,119,960	$ 2,029,567
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 287,517	$ 196,018
Accrued liabilities	77,338	63,795
Derivative liabilities	26,141	18,145
Deferred income taxes	1,443	—
Notes payable	55,000	24,000
Current maturities of long-term debt	11,771	16,166
Accrued income taxes	11,413	7,799
Liabilities of discontinued operations	—	7,679
	470,623	333,602
Long-term debt, net of current maturities	670,193	733,581
Deferred credits and other liabilities:		
Deferred income taxes	137,584	158,083
Derivative liabilities	2,623	211
Other	95,133	63,490
	235,340	221,784
Minority interest	4,925	4,835
Commitments and contingencies (Notes 7, 8, 9, 15, 19, 20 and 21)		
Stockholders' equity:		
Preferred stock – no par Series 2000-A; 0 and 21,500 shares authorized, respectively; issued and outstanding: 0 and 6,839 respectively	—	7,167
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 33,222,522 shares in 2005 and 32,595,285 shares in 2004	33,223	32,595
Additional paid-in capital	404,035	384,439
Retained earnings	313,217	322,009
Treasury stock at cost – 66,938 shares in 2005 and 117,567 shares in 2004	(1,766)	(2,838)
Accumulated other comprehensive loss	(9,830)	(7,607)
	738,879	728,598
Total stockholders' equity	738,879	735,765
	$ 2,119,960	$ 2,029,567

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,	2005	2004	2003
		(in thousands)	
Operating activities:			
Income from continuing operations before changes in accounting principle	$ 35,760	$ 61,190	$ 62,271
Adjustments to reconcile net income available for common to net cash provided by operating activities-			
Depreciation, depletion and amortization	89,306	74,040	66,523
Impairment of long-lived assets	52,175	—	117,207
Issuance of treasury stock for operating expense	1,917	1,030	2,151
Change in provision for valuation allowances	(1,289)	(2,575)	1,773
Net change in derivative assets and liabilities	(6,536)	2,541	(1,676)
Deferred income taxes	(8,385)	28,318	(4,563)
(Undistributed) distributed earnings in associated companies, net	(948)	3,762	(3,874)
Minority interest	277	186	—
Change in operating assets and liabilities-			
Accounts receivable and other current assets	(108,976)	(86,055)	(72,348)
Accounts payable and other current liabilities	94,092	39,387	(5,846)
Other operating activities	22,346	7,080	4,054
Net cash provided by operating activities of continuing operations	169,739	128,904	165,672
Net cash provided by operating activities of discontinued operations	5,110	8,101	5,467
Net cash provided by operating activities	174,849	137,005	171,139
Investing activities:			
Property, plant and equipment additions	(138,628)	(82,873)	(82,573)
Proceeds from sale of business operations	103,010	500	185,926
Payment for acquisition of net assets, net of cash acquired	(65,118)	—	—
Payment for acquisition of minority interest	—	—	(9,000)
Increase in notes receivable – Mallon Resources	—	—	(5,164)
Other investing activities	(3,861)	(2,392)	(3,566)
Net cash provided by investing activities of continuing operations	(104,597)	(84,765)	85,623
Net cash provided by investing activities of discontinued operations	(5,110)	(8,101)	(7,780)
Net cash provided by investing activities	(109,707)	(92,866)	77,843
Financing activities:			
Dividends paid on common and preferred stock	(42,212)	(40,531)	(37,283)
Common stock issued	12,212	4,031	121,283
Increase (decrease) in short-term borrowings, net	31,000	24,000	(340,500)
Long-term debt – issuance	—	18,650	252,000
Long-term debt – repayments	(94,171)	(155,021)	(139,310)
Other financing activities	(2,279)	(3,519)	(8,924)
Net cash provided by financing activities of continuing operations	(95,450)	(152,390)	(152,734)
Net cash provided by financing activities of discontinued operations	—	—	—
Net cash provided by financing activities	(95,450)	(152,390)	(152,734)
Increase (decrease) in cash and cash equivalents	(30,308)	(108,251)	96,248
Cash and cash equivalents:			
Beginning of year	64,506	(172,757	76,509*
End of year	$ 34,198	$ 64,506	$ 172,757
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 47,987	$ 49,546	$ 51,452
Income taxes paid (refunded)	$ 12,743	$ (21,927)	$ 58,660
Net assets acquired with non-cash consideration	$ —	$ —	$ 64,335

*Includes approximately $2.3 million of cash included in the assets of discontinued operations

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 Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)				
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 17)	—	—	—	—	—	—	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 17)	—	—	—	—	—	—	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
Comprehensive Income:								
Net income	—	—	—	33,420	—	—	—	33,420
Other comprehensive loss, net of tax (see Note 17)	—	—	—	—	—	—	(2,223)	(2,223)
Total comprehensive income	—	—	—	33,420	—	—	(2,223)	31,197
Dividends on preferred stock	—	—	—	(159)	—	—	—	(159)
Dividends on common stock	—	—	—	(42,053)	—	—	—	(42,053)
Issuance of common stock	628	628	18,751	—	—	—	—	19,379
Treasury stock issued, net	—	—	845	—	(51)	1,072	—	1,917
Balance at December 31, 2005	33,223	$ 33,223	$ 404,035	$ 313,217	67	$ (1,766)	$ (9,830)	$ 738,879

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 diversified energy company and with its subsidiaries operates in two primary operating groups: retail services and wholesale energy. Retail services include public utility electric operations through its subsidiary, Black Hills Power, Inc., and public utility electric and gas operations through its subsidiary, Cheyenne Light, Fuel and Power (Cheyenne Light), which was acquired on January 21, 2005 (see Note 23). 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. For further descriptions of the Company's business segments, see Note 22.

In June 2005, the Company sold its subsidiary, Black Hills FiberSystems, Inc., the Company's communications segment and in April 2005 sold the Pepperell power plant, the last remaining power plant in the eastern region. 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. Amounts related to Black Hills FiberSystems, Landrica and the hydroelectric power plants are included in Discontinued operations on the accompanying Consolidated Financial Statements. See Note 18 for further details.

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, 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 and contingency accruals. 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, the Company consolidates 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 the equity method of 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 $10.1 million, $9.6 million and $10.3 million in 2005, 2004 and 2003, 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.

Reclassifications

Certain 2004 and 2003 amounts in the consolidated financial statements have been reclassified to conform to the 2005 presentation. These reclassifications had no effect on the Company's stockholders' equity or results of operations, as previously reported. The reclassifications primarily related to planned or completed divestitures and the related reclassification to discontinued operations.

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, 2005, the following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets:

		2005		2004
		(in thousands)		
Major Classification				
Materials and supplies	$	24,567	$	21,404
Fuel		7,544		2,211
Gas and oil held by energy marketing		94,642		64,860
Total materials, supplies and fuel*	$	126,753	$	88,475

* As of December 31, 2005 and 2004, market adjustments related to gas and oil held by energy marketing and recorded in inventory, were $6.6 million and $(9.0) million, respectively. As of December 31, 2005, market adjustments related to fuel held by the electric utility were $(0.2) million. (See Note 2 for further discussion of natural gas marketing trading activities.)

"Materials and supplies" and "Fuel" 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 and oil inventory is stated at the lower of cost or market on a weighted-average cost basis. To the extent that fuel and gas and oil held by energy marketing have been designated as the underlying hedged item in a "fair value" hedge transaction, those volumes are stated at market value using published industry quotations.

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. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $0.7 million, $0.2 million and $0.4 million in 2005, 2004 and 2003, 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. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. 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. Ordinary repairs and maintenance of property are charged to operations as incurred. Costs of major renewals and replacements are capitalized as property, plant and equipment.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves. For certain non-utility power plant components, a unit-of-production methodology based on plant hours run is used.

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 2005, 2004 or 2003.

Goodwill and Intangible Assets

The Company accounts for goodwill and intangible assets in accordance with SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). Under SFAS 142, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life continue to be amortized over their useful lives (but with no maximum life).

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, 2005 and 2004 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2003, net of accumulated amortization	$ 30,144	$ 40,070
Amortization expense	—	(3,320)
Reclassification to discontinued operations	—	(62)
Balance at December 31, 2004, net of accumulated amortization	30,144	36,688
Additions	3,915	3
Impairment losses	(1,897)	(5,567)
Acquisition-related tax adjustment	(626)	—
Amortization expense	—	(3,298)
Balance at December 31, 2005, net of accumulated amortization	$ 31,536	$ 27,826

Intangible assets primarily relate to site development fees and acquired 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 $51.3 million, with accumulated amortization of $23.5 million at December 31, 2005 and $58.4 million, with accumulated amortization of $21.7 million at December 31, 2004. Amortization expense for intangible assets was $3.3 million, $3.3 million and $4.0 million in 2005, 2004 and 2003, respectively. Amortization expense for existing intangible assets is expected to be approximately $3.1 million a year through 2009 and $2.3 million in 2010.

Additions to goodwill relate to the acquisition of Cheyenne Light and represent the cost of the investment over the estimated fair value of the underlying net assets on the date of acquisition (see Note 23).

During the fourth quarter of 2005, the Company wrote off goodwill of approximately $1.9 million, net of accumulated amortization of $0.3 million related to partnership “equity flips” at certain power fund investments. Upon the triggering of the “equity flips,” the Company recognized earnings for the value of its additional partnership equity and impaired the related goodwill.

During the third quarter of 2005, the Company wrote off intangible assets of $5.6 million, net of accumulated amortization of $1.5 million, related to the impairment of the Las Vegas I gas-fired plant, due to uneconomic operations as a result of significant increases in forecasted natural gas prices (see Note 13).

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 12 and 13).

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 2005, a $50.3 million pre-tax impairment charge was recorded to reduce the carrying value of the Las Vegas I plant and related intangibles, and a $1.9 million, pre-tax impairment charge was recorded to reduce goodwill relating to the recognition of additional earnings in certain power fund investments. 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 and related intangibles (see Note 13).

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, is recognized currently in earnings.

Currency Adjustments

The Company's functional currency for all operations is the U.S. dollar. 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 Statements of Income as incurred.

Deferred Financing Costs

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

Development Costs

The Company generally expenses, when incurred, development and acquisition costs associated with corporate development activities prior to the Company acquiring or beginning construction of a project. Certain incremental direct costs for projects deemed by management to be probable of completion are capitalized as deferred assets. Expensed development costs are included in Administrative and general operating expenses on the accompanying consolidated financial statements. Capitalized development costs at December 31, 2005 and 2004 were $0 and $7.6 million, respectively, and are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

Legal Costs

Litigation settlements are recorded when it is probable the Company is liable for the costs and the liability can be reasonably estimated. Litigation settlement accruals are recorded net of expected insurance recovery. Legal costs related to settlements are not accrued, but expensed as incurred.

Minority Interest in Subsidiaries

Minority interest in the accompanying Consolidated Statements of Income and Balance Sheets represents the non-affiliated equity investors' interest in Wygen Funding, L.P., a variable interest entity as defined by Interpretation No. 46 "Consolidation of Variable Interest Entities" (FIN 46) (see Note 6).

Earnings attributable to minority ownership are generally shown on the accompanying Consolidated Statement of Income on a pre-tax basis as the minority investor is a limited partnership which pays no tax at the corporate level.

Regulatory Accounting

The Company's subsidiaries, Black Hills Power and Cheyenne Light, are subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

The regulated utilities follow the provisions of SFAS 71, and their financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating the utilities. If rate recovery 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 the utilities' 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, 2005 and 2004, the Company had regulatory assets of $17.3 million and $7.2 million and regulatory liabilities of $18.4 million and $6.0 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, unamortized losses on reacquired debt and deferred purchased power, transmission and natural gas costs from Cheyenne Light customers through an electric cost adjustment (ECA) and gas cost adjustment (GCA) mechanism. Each year Cheyenne Light files with the Wyoming Public Service Commission (WPSC) an ECA, effective January 1, and a GCA, effective October 1, to be included in tariff rates for the following year. The ECA and GCA are based on forecasts of the upcoming year's energy costs and recovery of prior year unrecovered costs. To the extent that energy costs are under recovered or over recovered during the year, they are recorded as a regulatory deferred asset or liability, respectively. These deferred energy balances are interest bearing. As of December 31, 2005, the Company had a deferred energy asset balance. 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 increase in regulatory liabilities in 2005 is primarily due to the cost of removal for Cheyenne Light, which was acquired in January 2005. 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.

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, certain 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. 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 changes in accounting principles" 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):

	2005		2004		2003	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 35,760		$ 61,190		$ 62,271	
Less: preferred stock dividends	(159)		(321)		(258)	
Basic – Income from continuing operations	35,601	32,765	60,869	32,387	62,013	30,496
Dilutive effect of:						
Stock options	—	160	—	96	—	102
Convertible preferred stock	159	97	321	195	258	222
Contingent shares issuable for prior acquisition	—	159	—	159	—	158
Others	—	107	—	75	—	37
Diluted – Income from continuing operations	$ 35,760	33,288	$ 61,190	32,912	$ 62,271	31,015

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):

	2005	2004	2003
Options to purchase common stock	123	484	334
Restricted stock	—	—	21
	123	484	355

Stock-based Compensation

At December 31, 2005, 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):

	2005	2004	2003
Net income available for common stock, as reported	$ 33,261	$ 57,652	$ 60,964
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(689)	(861)	(943)
Pro forma net income	$ 32,572	$ 56,791	$ 60,021
Earnings (loss) per share:			
As reported –			
Basic			
Continuing operations	$ 1.09	$ 1.88	$ 2.03
Discontinued operations	(0.07)	(0.10)	0.14
Change in accounting principles	—	—	(0.17)
Total	$ 1.02	$ 1.78	$ 2.00
Diluted			
Continuing operations	$ 1.07	$ 1.86	$ 2.01
Discontinued operations	(0.07)	(0.10)	0.13
Change in accounting principles	—	—	(0.17)
Total	$ 1.00	$ 1.76	$ 1.97
Pro forma –			
Basic			
Continuing operations	$ 1.06	$ 1.85	$ 2.01
Discontinued operations	(0.07)	(0.10)	0.13
Change in accounting principles	—	—	(0.17)
Total	$ 0.99	$ 1.75	$ 1.97
Diluted			
Continuing operations	$ 1.05	$ 1.83	$ 1.97
Discontinued operations	(0.07)	(0.10)	0.13
Change in accounting principles	—	—	(0.16)
Total	$ 0.98	$ 1.73	$ 1.94

Recently Issued Accounting Pronouncements

SFAS No. 123 (Revised 2004)

On December 16, 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statement No. 123 (Revised 2004) “Share-Based Payment,” or SFAS 123(R), which is a revision of SFAS Statement No. 123, “Accounting for Stock-Based Compensation.” SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

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) for stock options. Had the Company applied the fair value recognition provisions of SFAS 123-R during those periods, total stock-based employee compensation expense, net of related tax effects, would have been $0.7 million, $0.9 million and $0.9 million for the years ended December 31, 2005, 2004 and 2003, respectively.

As of the required effective date, the Company will apply SFAS 123-R using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. The Company estimates the adoption of SFAS 123-R will result in less than $0.3 million (after-tax) in additional stock-based compensation expense for the year ending December 31, 2006.

SAB 106

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 106, (SAB No. 106) to be effective October 1, 2004. SAB No 106 provides interpretive guidance on how full cost companies should reflect asset retirement obligations, or ARO, in their full cost ceiling and depreciation, depletion and amortization expense calculations. SAB No. 106 requires future cash outflows associated with settling ARO’s that have accrued on the balance sheet to be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. SAB No. 106 also requires the inclusion of the estimated amount of ARO that will be incurred as a future development activity on proved reserves in the costs to be amortized. Since we were already applying the provisions of SAB No. 106, there was no impact on us after adoption.

FIN 47

In March 2005 the FASB issued FIN 47, “Accounting for Conditional Asset Retirement Obligations.” This interpretation clarifies that the term *conditional asset retirement obligation* as used in FASB Statement No. 143, “Accounting for Asset Retirement Obligations,” (SFAS 143) refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred – generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists.

The Company has identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in its Oil and gas segment, reclamation of its coal mining sites in its Coal mining segment, and removal of fuel tanks and transformers containing polychlorinated biphenyls (PCBs) at the Electric and gas utility segment. The Company adopted FIN 47 effective December 31, 2005, which did not have a material impact on the Company's consolidated financial position, results of operations or cash flows.

<u>EITF Issue No. 04-6</u>

On March 17, 2005, the Emerging Issues Task Force (EITF) issued EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry" (EITF 04-6). EITF 04-6 provides that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. The Company currently has a deferred asset recorded, representing costs of removing overburden from coal deposits, and amortizes the deferred asset on a units-of-production basis in proportion of coal tonnage mined and sold to estimated coal tonnage uncovered. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. Upon adoption of EITF 04-6 on January 1, 2006, the Company recorded a $3.1 million cumulative effect adjustment to write-off previously recorded deferred charges, with the offset decreasing retained earnings. Additionally, future stripping costs will be expensed as a cost of inventory produced at the time incurred.

<u>EITF Issue No. 04-13</u>

On September 28, 2005 the FASB ratified the consensus reached under EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," (EITF 04-13) which determines if such transactions should be reported on a gross basis or a net basis. EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, in reporting periods beginning after March 16, 2006. The adoption will not have a significant effect on the Company's consolidated financial position, results of operations or cash flows.

(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 long position with crude oil and natural gas reserves and 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 interest rate and commodity markets.

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 by the Company's risk policies and procedures. 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.

For the years ended December 31, 2005, 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. 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. 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. EITF 02-3, 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.

Upon adoption of EITF 02-3 on January 1, 2003, the Company recorded a charge for a cumulative effect of an accounting change totaling approximately $2.9 million, net of tax. This cumulative effect of an accounting change was the result of certain energy contracts in our Energy marketing and transportation segment, previously marked to fair value under EITF 98-10, being restated to reflect historical cost. The amount of the cumulative effect represents the unrealized gain or loss recorded on these contracts as of January 1, 2003.

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

	2005		2004	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu)				
Natural gas basis swaps purchased	43,507	22	24,942	15
Natural gas basis swaps sold	53,665	22	27,145	15
Natural gas fixed-for-float swaps purchased	17,083	23	27,274	15
Natural gas fixed-for-float swaps sold	24,871	23	32,206	12
Natural gas physical purchases	59,855	34	64,799	15
Natural gas physical sales	88,302	46	95,996	58
Natural gas options purchased	6,176	21	9,643	33
Natural gas options sold	6,176	21	9,613	33
(Dollars, in thousands)				
Canadian dollars purchased	$88,000	2	$10,800	1
Canadian dollars sold	$29,000	5	$38,000	4

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2005 and 2004, 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, 2005 and 2004 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (loss)
December 31, 2005	$ 20,326	$ 1,747	$ 20,751	$ 2,086	$ (764)
December 31, 2004	$ 21,399	$ 8	$ 13,314	$ 11	$ 8,082

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 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, 2005 and 2004, the market adjustments recorded in inventory were $6.6 million and $(9.0) million, respectively.

Activities Other than Trading

Crude Oil Marketing

The Company’s crude oil marketing operations sold effective March 1, 2006, executed physical crude oil purchase contracts with producers and resold into various crude oil markets. Through these transactions, the Company effectively locked in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio was essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. The Company did not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk was from small differences in contract terms, index risk, or credit risk. Any risk that the Company identified was managed and mitigated within the guidelines stipulated in the Company’s risk policies.

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 the contracts entered into in our crude oil marketing operations are marked-to-market.

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

	2005		2004	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of barrels)				
Crude oil purchased	3,016	0.4	1,669	1.0
Crude oil sold	3,016	0.4	1,651	1.0

As of December 31, 2005 and 2004, 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 our 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, 2005 and 2004, 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, 2005 and 2004, 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, 2005 and 2004 the Company had the following swaps and related balances (in thousands):

December 31, 2005	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/options	300,000	1.00	$ 150	$ —	$ 2,535	$ 307	$ (2,842)	$ 150
Natural gas swaps	2,950,000	0.60	—	151	2,560	—	(2,409)	—
			$ 150	$ 151	$ 5,095	$ 307	$ (5,251)	$ 150
December 31, 2004								
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)

*Crude in bbls, gas in MMBtu

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 2006. Based on December 31, 2005 market prices, a $5.1 million loss will be realized and reported in earnings during 2006. These estimated realized losses for 2006 were calculated using December 31, 2005 market prices. Estimated and actual realized losses will likely change during 2006 as market prices change.

Electric Utility

On December 31, 2005, the Company had the following swaps and related balances (in thousands):

December 31, 2005	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Unrealized Gain (Loss)
Natural gas swaps	275,000	0.25	$ 192	$ —	$ 219	$ —	$ (219)	$ 192

*gas in MMbtu

Based on December 31, 2005 market prices, a $0.2 million loss would be realized and reported in pre-tax earnings during the next twelve months related to the cash flow hedge. These estimated realized losses for the next twelve months were calculated using December 31, 2005 market prices. Estimated and actual realized losses will likely change during the next twelve months as market prices change.

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 Consolidated Balance Sheet and the related unrealized gain/loss on the Consolidated Statement of Income. As of December 31, 2005, the market adjustments recorded in inventory were $(0.2) million.

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 assumed by 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, 2005, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2005, the Company had $163.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 10 years and a fair value of $(0.3) million. These hedges are substantially effective and any ineffectiveness was immaterial. Of the $163.0 million of swaps, $88.0 million expired in January 2006.

On December 31, 2005 and 2004 the Company's interest rate swaps and related balances were as follows (in thousands):

	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 (Loss)	Pre-tax (Loss)
December 31, 2005									
Swaps on project financing	$ 163,000	4.43%	10	$ 13	$ —	$ 76	$ 230	$ (249)	$ (44)
December 31, 2004									
Swaps on project financing	$ 113,000	4.22%	1.75	$ 60	$ —	$ 1,226	$ 200	$ (1,366)	$ —

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2006. Based on December 31, 2005 market interest rates, less than $0.1 million will be realized as additional interest expense during 2006. Estimated and realized amounts will likely change during 2006 as market interest rates change.

At December 31, 2005, the Company had $292.5 million of outstanding, floating-rate debt of which $179.5 million was not offset with interest rate swap transactions that effectively convert a portion of the debt to a fixed rate. A 100 basis point increase in interest rates would cause annual interest expense to increase $2.2 million in 2006.

In June 2005, the Company repaid approximately $81.5 million of project level financing on its Fountain Valley power facility. The Company has an interest rate swap with a $25.0 million notional amount maturing in September 2006, that was previously designated as a cash flow hedge of the variable rate interest payments on this project level debt. In accordance with FAS 133, upon repayment of the debt the Company de-designated the interest rate swap as a cash flow hedge and reclassified approximately $0.3 million from Accumulated Other Comprehensive Loss into earnings as additional interest expense. Without hedge designation, future variability in the fair value of this derivative will be recorded as a gain or loss in earnings.

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, 2005 and 2004, the Company had outstanding forward exchange contracts to sell approximately $29.0 million and $38.0 million Canadian dollars, respectively. At December 31, 2005 and 2004, the Company also had outstanding forward exchange contracts to purchase approximately $88.0 million and $10.8 million Canadian dollars, respectively. These contracts had a fair value of $(1.0) million at December 31, 2005 and 2004, and have been recorded as Derivative Assets/Liabilities on the accompanying Consolidated Balance Sheets. The Company recognized foreign exchange losses of $1.0 million and $1.4 million and foreign exchange income of $0.7 million for the years ended December 31, 2005, 2004 and 2003, respectively. All forward exchange contracts outstanding at December 31, 2005 settle by May 2006.

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 a 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 attempts to mitigate its credit exposure by conducting its business primarily 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 other 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 utilities) was concentrated with investment grade companies. Approximately 82 percent of the credit exposure was with investment grade companies. For the 18 percent credit exposure with non-investment grade rated counterparties, approximately 79 percent of this exposure was supported through letters of credit, prepayments, parental guarantees or 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 5.3 percent and 3.7 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., Project Finance Fund III, L.P., and Caribbean Basin Power Fund, Ltd., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. During the fourth quarter of 2005, the Company wrote off goodwill of approximately $1.9 million, net of accumulated amortization of $0.3 million, related to increased partnership interest earned through fund performance triggered by "equity flips." The Company recognized earnings for the value of its additional partnership equity and impaired the related goodwill. The Company's carrying amount of its investment in the funds is $10.8 million and $10.5 million, as of December 31, 2005 and 2004, respectively. As of, and for the year ended December 31, 2005, the funds had assets of $124.2 million, liabilities of $1.4 million and net income of $34.4 million. As of, and for the year ended December 31, 2004, the funds had assets of $178.4 million, liabilities of $0.5 million and net income of $2.9 million.

  The power funds in which the Company invests apply the provisions of the AICPA Audit and Accounting Guide, "Audits of Investment Companies." This guidance among other things requires investments held by investment companies to be stated at fair value.

- 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 $4.3 million and $3.6 million as of December 31, 2005 and 2004, 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, 2005, these projects had assets of $19.4 million, liabilities of $11.4 million and net income of $1.1 million. 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 income of $0.3 million.

(4) PROPERTY, PLANT AND EQUIPMENT

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

Retail Services Electric Utility	2005	2005 Weighted Average Useful Life	2004	2004 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 317,792	45	$ 315,613	45	25-58
Transmission*	69,998	45	83,488	44	35-50
Distribution	222,305	32	198,583	32	20-40
Plant acquisition adjustment	4,870	—	4,870	—	—
General	31,678	18	30,658	18	7-40
Total electric plant	646,643		633,212		
Less accumulated depreciation and amortization	250,583		232,401		
Electric plant net of accumulated depreciation and amortization	396,060		400,811		
Construction work in progress	6,684		4,066		
Net electric plant	$ 402,744		$ 404,877		

* 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 have been reclassified from Transmission to Distribution assets.

Electric and Gas Utility	2005	2005 Weighted Average Useful Life	Lives (in years)
Electric plant:			
Transmission	$ 2,283	40	35-50
Electric distribution	60,620	40	20-40
General	95	25	7-40
Gas plant:			
Distribution	36,109	55	10-65
General	72	25	25
General	5,505	31	3-45
Total	104,684		
Less accumulated depreciation and amortization	3,851		
Total net of accumulated depreciation and amortization	100,833		
Construction work in progress	26,106		
Net electric and gas	$ 126,939		

Wholesale Energy	2005 Property, Plant and Equipment	2005 Less Accumulated Depreciation Depletion and Amortization	2005 Property, Plant and Equipment Net of Accumulated Depreciation	2005 Construction Work in Progress	2005 Net Property Plant and Equipment	2005 Weighted Average Useful Life	Lives (in years)
Coal mining	$ 73,817	$ 38,154	$ 35,663	$ 3,808	$ 39,471	16	3-39
Oil & gas	322,749	92,065	230,684	—	230,684	24	4-30
Energy marketing and transportation	30,561	4,828	25,733	330	26,063	21	3-40
Power generation	733,964	128,823	605,141	68	605,209	29	3-40
Other	8,600	4,357	4,243	45	4,288	4	3-10
	$ 1,169,691	$ 268,227	$ 901,464	$ 4,251	$ 905,715		

2004

Wholesale Energy	Property Plant and Equipment	Less Accumulated Depreciation Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	2004 Weighted Average Useful Life	Lives (in years)
Coal mining	$ 72,846	$ 36,922	$ 35,924	$ 521	$ 36,445	16	3-39
Oil & gas	259,695	81,165	178,530	—	178,530	24	3-40
Energy marketing and transportation	27,517	3,344	24,173	942	25,115	23	3-40
Power generation	791,275	112,124	679,151	1,110	680,261	29	3-40
Other	6,633	2,884	3,749	7,951	11,700	7	5-7
	$ 1,157,966	$ 236,439	$ 921,527	$ 10,524	$ 932,051		

(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, 2005, BHP’s investment in the Plant included $73.8 million in electric plant and $38.8 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. BHP’s share of direct expenses of the Plant was $6.1 million, $6.0 million and $5.8 million for the years ended December 31, 2005, 2004 and 2003, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 20, the Company’s coal mining subsidiary, Wyodak Resources, supplies PacifiCorp’s share of the 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 PacifiCorp for the Plant were $18.1 million, $16.2 million and $18.7 million for the years ended December 31, 2005, 2004 and 2003, 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, 2005 and 2004, BHP’s share of direct expenses was $0.2 million and $0.1 million, respectively. As of December 31, 2005, BHP’s investment in the transmission tie was $19.7 million, with $0.9 million of accumulated depreciation and is included in the corresponding captions in the accompanying Consolidated Balance Sheets.

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, 2005, the Company's investment in the Gas Plant included $4.1 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 $3.1 million, $2.5 million and $1.7 million for the years ended December 31, 2005, 2004 and 2003, respectively. The Company's share of direct expenses for the Gas Plant were $0.3 million, $0.3 million and $0.2 million for the years ended December 31, 2005, 2004 and 2003, 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 I plant. Under the accounting interpretation, as amended, the Company consolidated the VIE effective December 31, 2003.

Prior to the December 31, 2003 consolidation, the Company recorded lease expense on the Wygen I 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, 2005 and 2004, depreciation expense was $3.7 million and $3.4 million, respectively; and interest expense was $6.0 million and $3.6 million, respectively.

(7) LONG-TERM DEBT

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

	2005	2004
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes	(215)	(244)
	224,785	224,756
First mortgage bonds:		
Electric utility		
8.06% due 2010	30,000	30,000
9.49% due 2018	3,680	3,970
9.35% due 2021	26,640	28,305
7.23% due 2032	75,000	75,000
Electric and gas utility		
7.50% due 2024	7,400	—
Industrial development revenue bonds, variable rate, at 3.65% due 2021[c]	7,000	—
Industrial development revenue bonds, variable rate, at 3.65% due 2027[c]	10,000	—
Unamortized debt premium on 7.5% first mortgage bonds due 2024	1,694	—
	161,414	137,275
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014[a]	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024[a]	12,200	12,200
GECC Financing at 6.54% due 2010[b][c]	26,213	28,213
Other	4,464	5,362
	49,327	52,225
Project financing floating rate debt:		
Fountain Valley project at 4.31% repaid 2005	—	82,661
Valmont and Arapahoe at 6.04% due 2007[c]	118,174	124,565
Wygen I project at 4.84% due 2006[c] [d]	111,100	111,100
Wygen I project at 4.84% due 2008[c]	17,164	17,165
	246,438	335,491
Total long-term debt	681,964	749,747
Less current maturities	(11,771)	(16,166)
Net long-term debt	$ 670,193	$ 733,581

(a) In the fourth quarter of 2004, the Company's electric utility called and refinanced $18.7 million of pollution control revenue bonds.
(b) Floating rate debt, 86 percent secured by Gillette combustion turbine and 14 percent secured by a spare LM6000 turbine.
(c) Interest rates are presented as of December 31, 2005.
(d) The Company intends to exercise an available two-year extension in June 2006.

At December 31, 2005, approximately 39 percent, or $113.0 million, of the Company's $292.5 million variable rate debt balance has been hedged with interest rate swaps converting floating rates to fixed rates with a weighted average interest rate of 4.43 percent (see Note 2).

Substantially all of the Company’s utility property is subject to the lien of the indentures securing its first mortgage bonds. First mortgage bonds of the utilities 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 Valmont and Arapahoe project debt is non-recourse debt. The Wygen I project debt is additionally guaranteed by the Company (see Note 21).

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, or issued waivers for, at December 31, 2005. Also, certain of the subsidiaries’ debt agreements provide that approximately $8.5 million of the subsidiaries’ cash balance at December 31, 2005 may not be distributed to the parent company.

Scheduled maturities of long-term debt for the next five years are: $11.8 million in 2006, $115.7 million in 2007, $132.5 million in 2008, $4.3 million in 2009 and $50.5 million in 2010.

(8) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $400.0 million at December 31, 2005 and $350.0 million at December 31, 2004. The $400.0 million line of credit outstanding at December 31, 2005 is a revolving credit facility, which terminates May 4, 2010. The Company had $55.0 million of borrowings and $60.7 million of letters of credit and $24.0 million of borrowings and $44.6 million of letters of credit issued on the lines at December 31, 2005 and 2004, respectively. The Company has no compensating balance requirements associated with these lines of credit.

On May 5, 2005, we entered into a new $400.0 million revolving bank facility with ABN AMRO as Administrative Agent, Union Bank of California and US Bank as Co-Syndication Agents, Bank of America and Harris Nesbitt as Co-Documentation Agents, and other syndication participants. The new facility has a five year term, expiring May 4, 2010. The facility contains a provision which allows the facility size to be increased by up to an additional $100.0 million through the addition of new lenders, or through increased commitments from existing lenders, but only with the consent of such lenders. The cost of borrowings or letters of credit issued under the new facility is determined based on our credit ratings; at our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70.0 basis points over the LIBOR (which equates to a 5.09 percent one-month borrowing rate as of December 31, 2005). In conjunction with entering into the new revolving bank facility, we terminated our $125.0 million revolving bank facility due May 12, 2005 and our $225.0 million facility due August 20, 2006.

In addition to the above lines of credit, at December 31, 2005, Enserco Energy (Enserco) has a $200.0 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 November 30, 2006. The Company has made a $3.0 million guarantee to the lender associated with the line of credit. At December 31, 2005 and 2004, there were outstanding letters of credit issued under the facility of $165.1 million and $91.7 million, respectively, with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. (BHER), our oil marketing unit, has maintained an uncommitted, discretionary credit facility. The facility allowed BHER to elect from $25.0 million up to $60.0 million of available credit via notification to the bank at the beginning of each calendar quarter. The line of credit provided credit support for the purchase of crude oil by BHER. At December 31, 2005, BHER had elected to have $50.0 million of available credit and had letters of credit outstanding of $48.5 million. On March 1, 2006, in conjunction with the sale of assets of BHER, the facility was terminated.

The credit facility 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. At December 31, 2005, the Company and its subsidiaries were in compliance with, or issued waivers for, the debt covenants. These facilities do not contain default provisions pertaining to credit rating status.

(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, reclamation of our coal mining sites in our Coal mining segment and removal of fuel tanks and transformers containing PCB's at the electric and gas utility 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 in 2003 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 12/31/04	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/05
Oil and gas	$ 7,942	$ 277	$ —	$ 572	$ 8,791
Mining	15,867	434	(928)	612	15,985
Electric and gas utility	—	182	—	—	182
Total	$ 23,809	$ 893	$ (928)	$ 1,184	$ 24,958

(10) COMMON AND PREFERRED STOCK

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 and performance shares. The Company has 1,168,873 shares available to grant at December 31, 2005. 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, 2005, 2004 and 2003, 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 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, 2005, 2004 and 2003, and changes during the years then ended are as follows:

	2005		2004		2003	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,289,869	$28.14	1,211,122	$27.66	1,042,989	$27.68
Granted	14,400	30.71	203,000	29.81	289,665	28.01
Forfeited	(42,705)	30.33	(53,154)	31.54	(66,153)	34.31
Exercised	(407,357)	25.03	(71,099)	22.12	(55,379)	22.00
Balance at end of year	854,207	$29.56	1,289,869	$28.14	1,211,122	$27.66
Exercisable at end of year	660,562	$29.66	885,894	$27.68	747,482	$26.45

Details of outstanding options at December 31, 2005 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	148,000	$21.76	4.0 years	148,000	$21.76
$22.01 to $27.00	116,653	$24.50	5.2 years	116,653	$24.50
$27.01 to $32.00	394,989	$29.18	7.7 years	203,344	$29.21
$32.01 to $37.00	98,065	$34.37	6.2 years	98,065	$34.37
$37.01 to $38.68	60,500	$37.74	5.1 years	58,500	$37.76
$55.36	36,000	$55.36	5.4 years	36,000	$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:

	2005	2004	2003
Weighted average fair value of options at grant date	$6.93	$6.90	$6.35
Weighted average risk-free interest rate	3.90%	3.82%	3.09%
Weighted average expected price volatility	42.27%	43.52%	46.80%
Weighted average expected dividend yield	4.17%	4.16%	4.28%
Expected life in years	7	7	7

In recent years, the Company maintained an Employee Stock Purchase Plan (ESPP) under which it sold shares to employees at 90 percent of the stock's market price on the offering date. The Company issued 15,644 and 24,963 shares of common stock under the ESPP in 2004 and 2003, respectively. The Company discontinued the ESPP Plan in 2005.

The Company issued 2,594, 16,019 and 45,123 restricted stock units in 2005, 2004 and 2003, respectively, and 58,461, 34,828 and 24,643 restricted common shares, in 2005, 2004 and 2003, respectively. The shares carry a restriction on the 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 $1.5 million in 2005, $1.7 million in 2004 and $0.9 million in 2003. The Company also issued 13,326 and 11,215 shares of common stock for the conversion of restricted stock units in 2005 and 2004.

Certain officers of the Company and its subsidiaries are participants in a performance share award plan. Performance shares are awarded 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	Target Grant of Shares
March 1, 2004	March 1, 2004 - December 31, 2005	15,548
March 1, 2004	March 1, 2004 - December 31, 2006	31,384
January 1, 2005	January 1, 2005 - December 31, 2007	41,499

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 was $1.5 million and $0.5 million for the years ended December 31, 2005 and 2004, respectively. The performance awards are paid in 50 percent cash and 50 percent common stock.

The Company issued 3,266, 10,310 and 3,075 shares of common stock in 2005, 2004 and 2003, respectively to certain key employees under the Short-term Annual Incentive Plan. The weighted average grant date fair value of the stock awards was $31.17, $31.10 and $23.10, 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 has been funding the Plan by the purchase of shares of common stock on the open market since June 2004. The Company issued 22,934 new shares in 2004 at a weighted average price of $30.41 and 94,346 new shares in 2003 at a weighted average price of $28.90. At December 31, 2005, 166,820 shares of unissued common stock were available for future offering under the Plan.

Other Common Stock Transactions

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 $118.0 million after commissions and expenses. The proceeds were used to pay off a $50 million credit facility and to repay $68.0 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 23).

During 2003, the Company issued a total of 12,575 common shares, 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 in 2003, which was based on the market value of the stock on the grant date.

Dividend Restrictions

The Company's credit facility contains 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 facility. The most restrictive financial covenants include the following: fixed charge coverage ratio of not less than 2.5 to 1.0; a recourse leverage ratio not to exceed 0.65 to 1.00; and a minimum consolidated net worth of $625 million plus 50 percent of our aggregate consolidated net income since January 1, 2005. As of December 31, 2005, we were in compliance with the above covenants.

Treasury Shares Acquired

The Company acquired 2,771, 4,005 and 4,400 shares of treasury stock related to forfeitures of unvested restricted stock in 2005, 2004 and 2003, respectively, and 16,872, 7,508 and 3,119 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 2005, 2004 and 2003, respectively.

Preferred Stock

On July 7, 2005, the 6,839 outstanding shares of the company's Preferred Stock Series 2000-A were automatically converted into 195,599 shares of the Company's common stock. The preferred shares valued at $1,000 per share plus the accrued and unpaid dividends were converted into common shares based upon a $35.00 per share conversion price. No shares of preferred stock remain outstanding after this transaction.

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 34,198	$ 34,198	$ 6 4,506	$ 64,506
Restricted cash	$ —	$ —	$ 3,069	$ 3,069
Derivative financial instruments - assets	$ 22,579	$ 22,579	$ 23,514	$ 23,514
Derivative financial instruments - liabilities	$ 28,764	$ 28,764	$ 18,356	$ 18,356
Notes payable	$ 55,000	$ 55,000	$ 24,000	$ 24,000
Long - term debt, including current maturities	$ 681,964	$ 709,459	$ 749,747	$ 788,212

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.

(12) 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.

(13) IMPAIRMENT OF LONG - LIVED ASSETS AND CAPITALIZED DEVELOPMENT COSTS

Due to a significant increase in the long-term forecasts for natural gas prices during the third quarter of 2005, the operation of the Company's Las Vegas I gas-fired power plant (Las Vegas I) became uneconomic. Accordingly, the Company assessed the recoverability of the carrying value of Las Vegas I in accordance with the provisions of SFAS No. 144 "Accounting for the Impairment of Long-lived Assets" (SFAS 144).

Las Vegas I is a 53 megawatt, natural gas-fired, combined-cycle turbine operating under a contract as a qualifying facility as defined by the Public Utility Regulatory Policies Act of 1978. Under the contract, which extends through 2024, the Company sells capacity and energy to Nevada Power Company. Fuel requirements for the plant are not externally hedged and have been provided at market index prices under a long-term supply arrangement. While the Company's oil and gas exploration and production operation produces gas sufficient to cover the plant's fuel requirements thus providing an internal hedge, SFAS 144 requires the determination of asset impairment at each asset group which has separately identifiable cash flows.

The carrying value of the assets tested for impairment was $60.3 million. The assessment resulted in an impairment charge of $50.3 million to write down the related Property, plant and equipment by $44.7 million, net of accumulated depreciation of $11.1 million, and intangible assets by $5.6 million, net of accumulated amortization of $1.5 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 Las Vegas I are included in the Power Generation segment.

During the fourth quarter of 2005, the Company wrote off goodwill of approximately $1.9 million, net of accumulated amortization of $0.3 million related to partnership "equity flips" at certain power fund investments. Upon the triggering of the "equity flips," the Company recognized earnings for the value of its additional partnership equity and impaired the related goodwill.

In addition, during 2005, the Company recorded a $9.9 million pre-tax charge for the write-off and expensing of certain capitalized costs for various energy development projects determined less likely to advance, and costs related to unsuccessfully bid projects during the third quarter of 2005. These charges are included in Administrative and general on the accompanying 2005 Consolidated Statement of Income. The Company determined these projects were less likely to advance, due to reduced economic feasibility of gas-fired power generation in the expected sustained high-priced natural gas environment, increased expectations of reliance on renewable or coal-fired generation, and a perceived preference of utilities in certain regions to acquire existing merchant generation at significant discounts as an alternative to entering into contracts for capacity and energy from new generation. These costs had previously been capitalized as management believed it was probable that such costs would ultimately result in acquisition or construction of the projects. This charge is included as a component of Administrative and general costs in “Operating expenses” on the accompanying Consolidated Statements of Income. For segment reporting the development costs are included in Corporate results.

As a result of the 2003 contract termination discussed in Note 12, 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.

(14) 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 22) 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.

(15) OPERATING LEASES

The Company has entered into lease agreements relating to certain power plant land leases, office facility leases and storage agreements. Rental expense incurred under these operating leases was $0.9 million, $0.8 million and $0.8 million for the years ended December 31, 2005, 2004 and 2003, respectively.

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

2006	$ 1,810
2007	1,456
2008	1,429
2009	1,324
2010	703
Thereafter	10,774
	$ 17,496

(16) INCOME TAXES

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

	2005	2004	2003
		(in thousands)	
Current:			
Federal	$ 25,454	$ 2,770	$ 39,367
State	625	(2,705)	5,235
Foreign	605	448	—
	26,684	513	44,602
Deferred:			
Federal	(8,350)	29,712	(7,445)
State	280	(1,115)	(4,105)
Tax credit amortization	(315)	(279)	(318)
	$ 18,299	$ 28,831	$ 32,734

Foreign taxes represent Canadian income taxes incurred through the Company's Canadian operations.

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

Years ended December 31,	2005	2004
	(in thousands)	
Deferred tax assets, current:		
Asset valuation reserves	$ 1,644	$ 2,235
Mining development and oil exploration	633	377
Employee benefits	2,264	2,651
Items of other comprehensive income	2,066	1,680
Other	1,949	250
	8,556	7,193
Deferred tax liabilities, current:		
Prepaid expenses	2,347	2,156
Derivative fair value adjustments	1,650	188
Employee benefits	272	—
Items of other comprehensive income	73	618
Other	5,657	1,534
	9,999	4,496
Net deferred tax (liability) asset, current	$ (1,443)	$ 2,697
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 3,959	$ 873
Mining development and oil exploration	262	205
Employee benefits	10,844	5,965
Regulatory asset	1,717	1,387
Deferred revenue	677	931
State net operating loss	556	—
Items of other comprehensive income	1,720	1,149
Foreign tax credit carryover	1,345	—
Net operating loss (net of valuation allowance)	15,871	4,863
Asset impairment	57,659	40,061
Derivative fair value adjustment	119	—
Other	7,865	8,867
	102,594	64,301
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	166,183	165,545
Employee benefits	3,151	3,608
Regulatory liability	3,984	4,172
Mining development and oil exploration	55,264	34,126
Derivative fair value adjustments	21	110
Items of other comprehensive income	53	115
Other	11,522	14,708
	240,178	222,384
Net deferred tax liability, non-current	$ 137,584	$ 158,083
Net deferred tax liability	$ 139,027	$ 155,386

The following table reconciles the change in the net deferred income tax liability from December 31, 2004 to December 31, 2005 to deferred income tax benefit:

		2005 (in thousands)
Net change in deferred income tax liability from the preceding table	$	(16,359)
Deferred taxes reclassified to current due to the sale of Black Hills FiberSystems, Inc.		7,371
Deferred taxes associated with other comprehensive loss		1,167
Deferred taxes related to net operating loss acquisitions		10,538
Deferred taxes related to acquisition		(11,712)
Other		610
Deferred income tax benefit for the period	$	(8,385)

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

	2005	2004	2003
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	1.1	(3.2)	0.8
Amortization of excess deferred and investment tax credits	(0.8)	(0.5)	(0.5)
Percentage depletion in excess of cost	(2.0)	(0.8)	(0.9)
Goodwill impairment	1.2	—	—
Research and development credit	—	—	(0.6)
Tax credits	(1.3)	—	—
Other	0.7	1.3	0.6
	33.9%	31.8%	34.4%

At December 31, 2005, the Company had the following remaining net operating loss carryforwards which were acquired as part of the Mallon and Pepperell acquisitions (in thousands):

	Net Operating Loss Carryforward	Expiration Year
$	481	2012
	512	2018
	1,103	2019
	4,207	2020
	2,852	2021
	6,001	2022
	1,800	2023

As of December 31, 2005, the Company had a valuation allowance of $1.5 million against these NOL carryforwards. Ultimate usage of these NOL’s depends upon the Company’s future tax planning and filings. If the valuation allowance is reduced due to higher than anticipated utilization of the NOL’s, the offsetting amount would reduce the Company’s financial reporting basis in its Mallon property.

In 2005, Canadian income tax returns were filed and accepted by Canada for the years of 1999 – 2003. Excess foreign tax credits were generated and are available to offset U.S. federal income taxes. At December 31, 2005, the Company had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year
$ 9	2009
236	2010
696	2011
345	2012
26	2013
33	2014

(17) 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):

	2005		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (1,344)	$ 470	$ (874)
Fair value adjustment of derivatives designated as cash flow hedges	(11,908)	4,156	(7,752)
Reclassification adjustments of cash flow hedges settled and included in net income	9,828	(3,440)	6,388
Unrealized gain (loss) on available-for-sale securities	23	(8)	15
Other comprehensive income (loss)	$ (3,401)	$ 1,178	$ (2,223)

	2004		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 91	$ (32)	$ 59
Fair value adjustment of derivatives designated as cash flow hedges	(4,818)	1,444	(3,374)
Reclassification adjustments of cash flow hedges settled and included in net income	10,508	(3,678)	6,830
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
Fair value adjustments of derivatives designated as cash flow hedges (net of minority interest share of $(331))	(10,103)	3,373	(6,730)
Reclassification adjustments of cash flow hedges settled and included in net income	9,511	(3,329)	6,182
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

(18) 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 “(Loss) income from discontinued operations, net of income taxes” 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 Black Hills FiberSystems

On April 20, 2005, the Company entered into an agreement to sell its Communications business, Black Hills FiberSystems, Inc. to Prairie*Wave* Communications, Inc. and completed the sale on June 30, 2005. Under the purchase and sale agreement, the Company received a cash payment of approximately $103 million.

Revenues and net income (loss) from the discontinued operations at December 31 are as follows (in thousands):

	2005	2004	2003
Revenues	$ 21,877	$ 39,586	$ 38,010
Pre-tax income (loss) from discontinued operations	$ 3,978	$ (6,068)	$ (8,923)
Pre-tax loss on disposal	(7,490)	—	—
Income tax benefit	1,405	2,127	3,133
Net loss from discontinued operations	$ (2,107)	$ (3,941)	$ (5,790)

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

	December 31, 2004
Current assets	$ 5,941
Property, plant and equipment	108,804
Non-current assets	57
Other current liabilities	(6,112)
Other non-current liabilities	(916)
Net assets of discontinued operations	$ 107,774

Sale of Pepperell Plant

During the third quarter of 2003, the Company adopted a plan to sell the 40 megawatt gas-fired Pepperell plant. On April 8, 2005, the Company sold the Pepperell plant to an unrelated party for a nominal amount plus the assumption of certain obligations. The sale of this facility was considered an asset sale and the Company retained the deferred tax asset, which was originally classified into Discontinued operations. 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:

	2005	2004 (in thousands)	2003
Operating revenues	$ —	$ 120	$ 2,152
Pre-tax loss from discontinued operations	(326)	(972)	(1,422)
Pre-tax loss on disposal	(39)	(1,064)	(3,464)
Income tax benefit	132	712	2,979
Net loss from discontinued operations	$ (233)	$ (1,324)	$ (1,907)

Assets and liabilities of the discontinued operations at December 31 are as follows (in thousands):

	2004
Current assets	$ 107
Non-current deferred tax asset	2,952
Other current liabilities	(167)
Non-current deferred tax liability	(484)
Net assets of discontinued operations	$ 2,408

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

Sale of Hydroelectric Assets

On September 30, 2003 the Company sold its seven hydroelectric power plants located in Upstate New York. 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 (in thousands):

		2003
Operating revenues	$	21,800
Pre-tax income from discontinued operations		7,986
Pre-tax gain on disposal		13,864
Income tax expense		(11,355)
Net income from discontinued operations	$	10,495

Sale of Coal Marketing Subsidiary

In July 2002, the Company disposed of its coal marketing subsidiary, Black Hills Coal Network.

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

		2003
Pre-tax loss from discontinued operations	$	—
Pre-tax loss on disposal		—
Income tax benefit		834
Net income from discontinued operations	$	834

(19) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

The Company sponsors two 401(k) savings plans. The Black Hills Corporation Retirement Savings Plan is for eligible employees of the Company and its subsidiaries, but excluding the employees of Cheyenne Light. The Cheyenne Light, Fuel and Power Company Retirement Savings Plan is for eligible employees of Cheyenne Light. For both plans, participants may elect to invest up to 20 percent of their eligible compensation on a pre-tax basis up to maximum amounts established by the Internal Revenue Service. The Black Hills Corporation plan provides a matching contribution of 100 percent of the employee's annual tax-deferred contribution up to a maximum of 3 percent of eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Cheyenne Light plan provides for two matching formulas depending on status as a bargaining unit employee or as a non-bargaining unit employee. Bargaining unit employees receive a maximum match of 5 percent of eligible compensation based upon the following formula: 100 percent of the employee's tax-deferred contribution on the first 3 percent of eligible compensation, plus 50 percent of the next 4 percent of eligible compensation. Non-bargaining unit employees receive a maximum match of 4 percent of eligible compensation based upon the following formula: 100 percent of the employee's tax-deferred contribution on the first 3 percent of eligible compensation, plus 50 percent of the next 2 percent of eligible compensation. Matching contributions under both formulas are immediately 100 percent vested. In addition, the Cheyenne Light plan provides for a profit sharing contribution for certain eligible Cheyenne Light employees equal to 3.5 percent to 10 percent of eligible compensation, depending on age and years of service. Profit sharing contributions become 100 percent vested after completion of 5 years of service. The Black Hills Corporation Retirement Savings Plan matching contributions were $1.5 million for 2005, $1.4 million for 2004 and $1.4 million for 2003. The Cheyenne Light Retirement Savings Plan matching contributions were $0.2 million for the initial plan year of 2005. The Cheyenne Light plan profit sharing contribution was $0.2 million for the initial plan year of 2005.

Defined Benefit Pension Plan

The Company has two noncontributory defined benefit pension plans (the Pension Plans). The Pension Plan of Black Hills Corporation (BHC Pension Plan) covers the employees of the Company and the employees of the subsidiaries Black Hills Power, Wyodak Resources Development Corp., and Black Hills Exploration and Production 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 Cheyenne Light, Fuel and Power Company Pension Plan (Cheyenne Light Pension Plan) covers the employees of the Company's subsidiary, Cheyenne Light, who meet certain eligibility requirements. The benefits for the bargaining unit employees of Cheyenne Light are based on years of service and compensation levels during the highest three consecutive 12-month periods of service, reduced by the vested New Century Accrued Pension Benefits, if any. The benefits for non-bargaining unit employees of Cheyenne Light are based on annual credits for each year of service plus investment credits. The Company's funding policy is in accordance with the federal government's funding requirements. The BHC Pension Plans' assets are held in trust and consist primarily of equity securities and cash equivalents. At December 31, 2005, the Cheyenne Light Pension Plan had no assets. The Company uses a September 30 measurement date for the Pension Plans.

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

The expected long-term rate of return for equity investments was 9.5 percent and 10.0 percent for the 2005 and 2004 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2005, 11.8 percent, 12.5 percent, 10.1 percent and 10.3 percent, respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on 10-year treasury bonds of 7.0 percent from 1962 to 2005, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term bonds.

Plan Assets

Percentage of fair value of BHC Pension Plan assets at September 30:

	2005	2004
Domestic equity	52.9%	59.7%
Foreign equity	40.6	34.5
Fixed income	3.4	2.6
Cash	3.1	3.2
Total	100.0%	100.0%

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

The BHC Pension 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 BHC Pension Plan will maintain a passive core U.S. Stock portfolio based on a broad market index. Complementing this core will be investments in U.S. and foreign equities through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the BHC 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 BHC Pension Plan assets if a fund engages in such transactions. The BHC Pension Plan has historically not invested in funds engaging in such transactions.

Cash Flows

The Company has made a $1.2 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2006; no additional contributions are anticipated to be made to the BHC Pension Plan or to the Cheyenne Light Pension Plan during the 2006 fiscal year.

Supplemental Nonqualified Defined Benefit Retirement Plans

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

<u>Plan Assets</u>

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

<u>Estimated Cash Flows</u>

The estimated employer contribution is expected to be $0.7 million in 2006. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

The Company sponsors two retiree healthcare plans (collectively, the Plans): the Black Hills Corporation Postretirement Healthcare Plan and the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company. Employees who are participants in the Black Hills Corporation Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits. Employees who are participants in the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company and who retire from Cheyenne Light on or after attaining age 55 and after completion of a number of consecutive years of service, which when added to the employee’s age totals 90, are entitled to postretirement healthcare benefits. The benefits for both plans are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change either plan periodically. The Company is not pre-funding either retiree healthcare plan. The Company uses a September 30 measurement date for both Plans.

It has been determined that the post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the 2005 fiscal year, was an actuarial gain of approximately $2.0 million. The effect on 2006 net periodic postretirement benefit cost will be a decrease of approximately $0.3 million.

<u>Plan Assets</u>

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

<u>Estimated Cash Flows</u>

The estimated employer contribution is expected to be $0.2 million in 2006. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the Employee Benefit Plan’s obligations and fair value of assets for 2005 and 2004, a statement of funded status for 2005 and 2004 and components of the net periodic expense for the years ended 2005, 2004 and 2003.

Benefit Obligations

	Defined Benefit Pension Plans 2005 (in thousands)	Defined Benefit Pension Plans 2004	Supplemental Nonqualified Defined Benefit Retirement Plans 2005 (in thousands)	Supplemental Nonqualified Defined Benefit Retirement Plans 2004	Non-pension Defined Benefit Postretirement Plans 2005 (in thousands)	Non-pension Defined Benefit Postretirement Plans 2004
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 64,760	$ 61,879	$ 16,980	$ 16,194	$ 10,992	$ 11,151
Projected benefit obligation of Cheyenne Light at acquisition	2,407	—	—	—	3,932	—
Service cost	2,214	1,772	344	536	705	561
Interest cost	3,940	3,637	1,009	965	874	662
Actuarial (gain) loss	(411)	(237)	1,257	(582)	(2,108)	(1,156)
Discount rate change	2,661	—	—	—	—	—
Change in assumptions	729	—	—	—	—	—
Benefits paid	(2,445)	(2,291)	(384)	(133)	(569)	(611)
Plan participant's contributions	—	—	—	—	449	385
Net increase (decrease)	9,095	2,881	2,226	786	3,283	(159)
Projected benefit obligation at end of year	$ 73,855	$ 64,760	$ 19,206	$ 16,980	$ 14,275	$ 10,992

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

	Defined Benefit Pension Plan 2005 (in thousands)	Defined Benefit Pension Plan 2004	Supplemental Nonqualified Defined Benefit Retirement Plans 2005 (in thousands)	Supplemental Nonqualified Defined Benefit Retirement Plans 2004	Non-pension Defined Benefit Postretirement Plans 2005 (in thousands)	Non-pension Defined Benefit Postretirement Plans 2004
Beginning market value of plan assets	$ 52,782	$ 48,797	$ —	$ —	$ —	$ —
Investment income	8,948	6,276	—	—	—	—
Benefits paid	(2,445)	(2,291)	—	—	—	—
Ending market value of plan assets	$ 59,285	$ 52,782	$ —	$ —	$ —	$ —

Funded Status

	Defined Benefit Pension Plans 2005 (in thousands)	Defined Benefit Pension Plans 2004	Supplemental Nonqualified Defined Benefit Retirement Plans (a) 2005 (in thousands)	Supplemental Nonqualified Defined Benefit Retirement Plans (a) 2004	Non-pension Defined Benefit Postretirement Plans 2005 (in thousands)	Non-pension Defined Benefit Postretirement Plans 2004
Funded status	$ (14,570)	$ (11,978)	$ (19,206)	$ (16,980)	$ (14,275)	$ (10,992)
Unrecognized net loss	18,150	20,674	9,877	9,249	330	2,538
Unrecognized prior service cost	1,162	1,377	43	53	(264)	(288)
Unrecognized transition obligation	—	—	—	—	1,049	1,198
Contributions	—	—	255	84	48	36
Net amount recognized	$ 4,742	$ 10,073	$ (9,031)	$ (7,594)	$ (13,112)	$ (7,508)

Amounts recognized in statement of financial position consist of:

	Defined Benefit Pension Plans (a) 2005	Defined Benefit Pension Plans (a) 2004	Supplemental Nonqualified Defined Benefit Retirement Plans (b) 2005	Supplemental Nonqualified Defined Benefit Retirement Plans (b) 2004	Non-pension Defined Benefit Postretirement Plans 2005	Non-pension Defined Benefit Postretirement Plans 2004
	(in thousands)		(in thousands)		(in thousands)	
Amounts recognized in consolidated balance sheets consist of:						
Net asset (liability)	$ 4,742	$ 10,073	$ (13,844)	$ (10,902)	$ (13,112)	$ (7,508)
Intangible asset	—	—	42	52	—	—
Contributions	—	—	255	84	—	—
Accumulated other comprehensive loss	—	—	4,516	3,172	—	—
Net amount recognized	$ 4,742	$ 10,073	$ (9,031)	$ (7,594)	$ (13,112)	$ (7,508)
Accumulated benefit obligation - BHC	$ 57,254	$ 51,690	$ 13,844	$ 10,902	$ 10,195	$ 10,992
Accumulated benefit obligation – Cheyenne Light	$ 1,328	$ —	$ —	$ —	$ 4,080	$ —

(a) The provisions of SFAS 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $4.7 million and $10.1 million at December 31, 2005 and 2004, respectively. This amount is included in Other assets, Other on the accompanying Consolidated Balance Sheets.
(b) The provisions of SFAS 87 required the Company to record a net pension liability of $13.8 million and $10.9 million at December 31, 2005 and 2004, respectively. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets.

Components of Net Periodic Expense

	Defined Benefit Pension Plans 2005	Defined Benefit Pension Plans 2004	Defined Benefit Pension Plans 2003	Supplemental Nonqualified Defined Benefit Retirement Plans 2005	Supplemental Nonqualified Defined Benefit Retirement Plans 2004	Supplemental Nonqualified Defined Benefit Retirement Plans 2003	Non-pension Defined Benefit Postretirement Plans 2005	Non-pension Defined Benefit Postretirement Plans 2004	Non-pension Defined Benefit Postretirement Plans 2003
		(in thousands)			(in thousands)			(in thousands)	
Service cost	$ 2,214	$ 1,772	$ 1,293	$ 344	$ 536	$ 425	$ 705	$ 561	$ 383
Interest cost	3,940	3,637	3,351	1,009	965	759	874	662	576
Expected return on assets	(4,628)	(4,515)	(3,119)	—	—	—	—	—	—
Amortization of prior service cost	215	232	232	9	9	(2)	(24)	(24)	(24)
Amortization of transition obligation	—	—	—	—	—	—	150	150	150
Recognized net actuarial loss	1,183	1,498	1,407	629	748	511	100	189	89
Net periodic expense	$ 2,924	$ 2,624	$ 3,164	$ 1,991	$ 2,258	$ 1,693	$ 1,805	$ 1,538	$ 1,174

Additional Information

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2005	2004	2005	2004	2005	2004
	(in thousands)		(in thousands)		(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ —	$ —	$ 1,344	$ 91	$ —	$ —

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2005	2004	2003	2005	2004	2003	2005	2004	2003
Discount rate	5.75%	6.00%	6.00%	5.75%	6.00%	6.00%	5.75%	6.00%	6.00%
Rate of increase in compensation levels	4.34%	4.39%	5.00%	5.00%	5.00%	5.00%	N/A	N/A	N/A
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2005	2004	2003	2005	2004	2003	2005	2004	2003
Discount rate	6.00%	6.00%	6.75%	6.00%	6.00%	6.75%	6.00%	6.00%	6.75%
Expected long-term rate of return on assets*	9.00%	9.50%	10.00%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.39%	5.00%	5.00%	5.00%	5.00%	5.00%	N/A	N/A	N/A

*The expected rate of return on plan assets was changed from 9.0 percent in 2005 to 8.5 percent for the calculation of the 2006 net periodic pension cost. This change is expected to increase pension expense in 2006 by approximately $0.3 million.

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

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 $0.4 million or 26 percent and the accumulated periodic postretirement benefit obligation $3.0 million or 21 percent. A 1 percent decrease would reduce the service and interest cost by $0.3 million or 20 percent and the accumulated periodic postretirement benefit obligation $2.3 million or 16 percent.

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

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Non-pension Defined Benefit Postretirement Plans		
			Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2006	$ 2,607	$ 733	$ 267	$ (28)	$ 239
2007	2,752	745	310	(31)	279
2008	2,921	770	368	(35)	333
2009	3,059	765	438	(38)	400
2010	3,305	795	538	(42)	496
2011 - 2015	20,722	4,675	3,854	(311)	3,543

(20) 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 I 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, 2005.

Power Purchase and Transmission Services Agreements – Pacific Power

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $10.1 million in 2005, $10.0 million in 2004 and $10.8 million in 2003.

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

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were $0.4 million in 2005, $0.4 million in 2004 and $0.5 million in 2003.

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 for the output of the 40 megawatt gas-fired Gillette CT, which expires August 2011. The Company assumes a portion of the fuel price risk under this agreement since the fuel price is fixed at the outset of each month and Cheyenne Light 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 Cheyenne Light. This agreement has been temporarily assigned from Cheyenne Light to its former affiliate, PSCo, for the four-year term of Cheyenne Light's all requirements power purchase agreement with PSCo, which expires December 31, 2007. The Company acquired Cheyenne Light on January 21, 2005 (see Note 23).

- The Company has a ten-year contract with Cheyenne Light for 60 megawatts of contingent capacity from the 90 megawatt Wygen I plant, which expires the first quarter of 2013. As with the Gillette CT contract, this agreement has been temporarily assigned to PSCo.

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

- The Company has a long-term contract for 45 megawatts of 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 commenced 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. We entered into a new power purchase agreement with MDU for the supply of up to 74 megawatts of capacity and energy for Sheridan, Wyoming from 2007 through 2016, which is subject to regulatory approval by the WPSC. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. The agreement renews automatically and requires a seven-year notice of termination. Both contracts are served by 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 $0.6 million, $0.7 million and $0.6 million was charged to accretion expense for the years ended December 31, 2005, 2004 and 2003, respectively. Approximately $0.4 million, $0.5 million and $0.3 million was charged to depreciation expense for the years ended December 31, 2005, 2004 and 2003, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $16.0 million and $15.9 million at December 31, 2005 and 2004, 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. A trial date has been set for late 2006. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the "Grizzly Gulch Fire." Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by 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 completed its own investigation of the fire cause and origin and 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. A trial date has been set for August 2006. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through June 2005, various private civil actions were filed against 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, all arising from the Grizzly Gulch Fire. A trial date has been set for August 2006.

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

PPM Energy, Inc. Demand for Arbitration

On January 2, 2004, PPM Energy, Inc. delivered a Demand for Arbitration to 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. The dispute was presented to the arbitrator in August 2005. The Company cannot predict the outcome of the decision.

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 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 Enserco comprise a relatively small part of only one category of the total claims included in this lawsuit. Enserco denied all claims for damages, and joined in motions to dismiss, which were unsuccessful.

Notwithstanding the Company's continued belief that the Class Plaintiffs present a flawed theory to recover actual damages as a result of the alleged conduct of former Enserco traders, in the third quarter of 2005 Enserco made a business decision to seek a settlement of claims made against it, due to mounting defense costs, and settlements by other defendant companies, which further increase the Company's ongoing share of joint-defense expenses. In early October 2005, motions to certify the action to proceed as a class action were granted. On October 28, 2005, the Company reached a tentative settlement with Plaintiffs, pursuant to which the Company would pay $2.6 million in full and final settlement of all claims. The parties await approval of the final settlement documents. The accompanying 2005 consolidated financial statements include a $2.6 million accrual for the settlement.

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. The federal court agreed, in part, with the Company's views concerning arbitration, and ordered that certain issues be determined in that forum. Accordingly, the parties will select an arbitrator and will resolve the disputes on a dual track, with certain issues remaining with the federal court to resolve. 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.

(21) 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.

As of December 31, 2005, the Company had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2005	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	2006
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2006
Guarantee of interest rate swap transaction with Union Bank of California	930	2006
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	250	2006
Guarantee obligations under the Wygen I Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	26,213	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	5,374	Ongoing
	$ 162,535	

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 by the Company 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. and other lenders 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 November 20, 2006.

The Company has guaranteed up to $0.9 million of the obligations of its power generation subsidiary, Black Hills Colorado, to Union Bank of California related to the obligations of an interest rate swap transaction with a notional amount of $25.0 million and a fixed interest rate of 4.96 percent. The swap expires September 29, 2006. At December 31, 2005 we had a liability included on the Consolidated Balance Sheet of less than $0.1 million associated with this swap.

The Company has guaranteed up to $0.3 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. In February 2006, the expiration date of the guarantee was extended to March 1, 2007.

The Company has guaranteed the obligations of Black Hills Wyoming under the Agreement for Lease and Lease for the Wygen I 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, 2005, 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 I plant). The initial term of the lease expires in 2008, with two five-year renewal options.

The Company has guaranteed the payment of $22.5 million of debt of Black Hills Wyoming and $3.7 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, 2005, the Company had guarantees in place totaling approximately $5.4 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.

(22) 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, 2005, 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 primarily in the western United States; and Retail Services consisting of: Electric utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana and Electric and gas utility, acquired January 21, 2005, which supplies electric and gas utility service to Cheyenne, Wyoming and vicinity.

On June 30, 2005, the Company completed the sale of its subsidiary, Black Hills FiberSystems, Inc., which operated as the Company's Communication segment (see Note 18). The financial information of Black Hills FiberSystems, Inc. has been reclassified into Discontinued operations on the accompanying consolidated financial statements.

Prior to 2004, the Company's communications segment also 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:	2005	2004
	(in thousands)	
Total assets		
Wholesale energy:		
Coal mining	$ 57,805	$ 55,133
Oil and gas	242,753	194,203
Energy marketing and transportation	448,840	348,230
Power generation	732,273	826,294
Retail services:		
Electric utility	460,489	465,432
Electric and gas utility	163,464	—
Communications	—	1,571
Corporate	14,336	20,843
Discontinued operations	—	117,861
Total assets	$ 2,119,960	$ 2,029,567
Capital expenditures and acquisitions		
Wholesale energy:		
Coal mining	$ 6,517	$ 3,183
Oil and gas	71,799	53,891
Energy marketing and transportation	2,429	622
Power generation	6,095	6,043
Retail services:		
Electric utility	18,162	13,347
Electric and gas utility	30,536	—
Corporate	3,090	5,787
Total capital expenditures and acquisitions	$ 138,628	$ 82,873
Property, plant and equipment		
Wholesale energy:		
Coal mining	$ 77,625	$ 73,367
Oil and gas	322,749	259,695
Energy marketing and transportation	30,891	28,459
Power generation	734,032	792,385
Retail services:		
Electric utility	653,327	637,278
Electric and gas utility	130,790	—
Corporate	8,645	14,584
Total property, plant and equipment	$ 1,958,059	$ 1,805,768

December 31:	2005	2004	2003
		(in thousands)	
External operating revenues			
Wholesale energy:			
Coal mining	$ 21,376	$ 19,669	$ 22,232
Oil and gas	87,536	59,191	46,648
Energy marketing and transportation	815,825	662,110	675,586
Power generation	158,399	158,037	284,567 [(a)]
Retail services:			
Electric utility	186,806	172,774	170,942
Electric and gas utility	110,875	—	—
Communications	—	—	1,753
Corporate	771	761	—
Total external operating revenues	$ 1,381,588	$ 1,072,542	$ 1,201,728

(a) Power generation revenue in 2003 includes $114 million of contract termination revenue as described in Note 12.

Intersegment operating revenues			
Wholesale energy:			
Coal mining	$ 12,901	$ 12,298	$ 12,545
Oil and gas	13	343	329
Retail services:			
Electric utility	2,199	971	77
Corporate	—	2,672	—
Intersegment eliminations	(5,057)	(6,711)	(2,639)
Total intersegment operating revenues[(b)]	$ 10,056	$ 9,573	$ 10,312

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

Depreciation, depletion and amortization			
Wholesale energy:			
Coal mining	$ 4,366	$ 5,142	$ 3,808
Oil and gas	22,114	13,028	10,000
Energy marketing and transportation	1,545	1,201	1,183
Power generation	35,583	34,535	31,727
Retail services:			
Electric utility	19,543	18,873	18,999
Electric and gas utility	4,532	—	—
Communications	—	—	247
Corporate	1,623	1,261	559
Total depreciation, depletion and amortization	$ 89,306	$ 74,040	$ 66,523

Operating income (loss)			
Wholesale energy:			
Coal mining	$ 7,892	$ 8,454	$ 8,775
Oil and gas	31,605	19,181	13,258
Energy marketing and transportation	23,283	18,181	12,151
Power generation	(2,154)	47,934	58,893
Retail services:			
Electric utility	36,044	43,809	51,099
Electric and gas utility	3,053	—	—
Communications	—	—	(132)
Corporate	(13,787)	(1,306)	(7,767)
Total operating income	$ 85,936	$ 136,253	$ 136,277

December 31:	2005	2004	2003
		(in thousands)	
Interest income			
Wholesale energy:			
Coal mining	$ 1,304	$ 1,393	$ 2,473
Oil and gas	39	12	832
Energy marketing and transportation	1,297	728	1,236
Power generation	20,914	24,559	23,720
Retail services:			
Electric utility	258	696	1,512
Electric and gas utility	613	—	—
Corporate	23,596	15,626	16,090
Intersegment eliminations	(46,165)	(41,256)	(44,787)
Total interest income	$ 1,856	$ 1,758	$ 1,076
Interest expense			
Wholesale energy:			
Coal mining	$ —	$ 226	$ 757
Oil and gas	3,922	1,578	2,054
Energy marketing and transportation	1,944	877	885
Power generation	45,069	49,758	53,854
Retail services:			
Electric utility	12,907	16,019	17,044
Electric and gas utility	708	—	—
Communications	—	—	13
Corporate	30,249	20,892	18,945
Intersegment eliminations	(46,165)	(41,256)	(44,787)
Total interest expense	$ 48,634	$ 48,094	$ 48,765
Income taxes			
Wholesale energy:			
Coal mining	$ 2,641	$ 2,574	$ 2,423
Oil and gas	10,511	5,315	3,978
Energy marketing and transportation	6,276	7,811	5,778
Power generation	(558)	6,711	11,795
Retail services:			
Electric utility	5,743	9,512	11,622
Electric and gas utility	844	—	—
Communications	—	—	(51)
Corporate	(7,158)	(3,092)	(2,811)
Total income taxes	$ 18,299	$ 28,831	$ 32,734
Income (loss) from continuing operations before change in accounting principle			
Wholesale energy:			
Coal mining	$ 6,947	$ 7,463	$ 8,289
Oil and gas	17,905	12,200	8,400
Energy marketing and transportation	16,359	10,222	6,725
Power generation	(12,524) (c)	15,562	22,429
Retail services:			
Electric utility	18,005	19,209	24,089
Electric and gas utility	2,114	—	—
Communications	—	—	(90)
Corporate	(13,046)	(3,462)	(7,569)
Intersegment eliminations	—	(4)	(2)
Total income from continuing operations before change in accounting principle	$ 35,760	$ 61,190	$ 62,271

(c) Loss from continuing operations includes a $33.9 million after-tax impairment charge for long-lived assets as described in Note 13.

(23) ACQUISITIONS

Cheyenne Light, Fuel and Power

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, Cheyenne Light. On January 21, 2005, the Company completed this acquisition. The Company purchased all the common stock of Cheyenne Light, including the assumption of outstanding debt of approximately $24.6 million, for approximately $90.7 million. The purchase price has been reduced to reflect final revisions to the estimated working capital included in the purchase payment on the date of the transaction closing.

This acquisition has been accounted for under the purchase method of accounting, and accordingly, the purchase price has been 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. Allocation of the purchase price (as revised for the working capital adjustment described above) is as follows (in thousands):

Current assets	$	18,036
Property, plant and equipment		94,506
Deferred assets and goodwill		20,139
	$	132,681
Current liabilities	$	12,546
Long-term debt		26,388
Deferred tax liabilities		7,408
Long-term liabilities		20,195
	$	66,537
Net assets	$	66,144

The results of operations of Cheyenne Light have been included in the accompanying Consolidated Financial Statements since the acquisition date.

The following pro-forma consolidated results of operations have been prepared as if the Cheyenne Light acquisition had occurred on January 1, 2003 (in thousands):

		2005		2004		2003
Operating revenues	$	1,400,822	$	1,178,244	$	1,309,075
Income from continuing operations		35,939		63,417		64,490
Net income available for common		33,440		59,879		63,183
Earnings per share –						
Basic:						
Continuing operations	$	1.09	$	1.95	$	2.11
Total	$	1.02	$	1.85	$	2.07
Diluted:						
Continuing operations	$	1.08	$	1.93	$	2.08
Total	$	1.00	$	1.83	$	2.05

The above pro-forma information is presented for informational purposes only and is not necessarily indicative of the results of operations that would have been achieved had the acquisition been consummated at that time; nor is it intended to be a projection of future results.

Power Plant Ownership Interests

On December 31, 2005, the Company purchased the following power plant ownership interests:

- an additional 50 percent ownership interest in the Company's Las Vegas I facility;
- an additional 50 percent ownership interest in the Company's Ontario facility;
- a 50 percent interest in two 11 megawatt, gas-fired plants located in Rupert and Glenns Ferry, Idaho (the Idaho Cogeneration Facilities).

The Company previously held demand promissory notes and related purchase options for these ownership interests. On December 31, 2005, the Company exercised its purchase option on the ownership interests with cancellation of the related promissory notes as full consideration paid.

The transactions had no impact on the Company's financial statements as prior to the transactions, under accounting principles generally accepted in the United States, the Company consolidated these ownership interests into our financial statements.

Mallon Resources Corporation

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 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 year ended December 31, 2003 has been prepared as if the Mallon acquisition had occurred on January 1, 2003 (in thousands):

		2003
Operating revenues	$	1,214,981
Income from continuing operations	$	61,823
Net income available for common	$	60,516
Earnings per share —		
Basic:		
Continuing operations	$	1.99
Total	$	1.95
Diluted:		
Continuing operations	$	1.96
Total	$	1.93

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.

(24) SUBSEQUENT EVENTS

Sale of Crude Oil Marketing and Transportation Assets

On January 5, 2006, the Company entered into a definitive agreement to sell the operating assets of its crude oil marketing and transportation business. The sale was completed on March 1, 2006. The Company received approximately $41.0 million of cash proceeds, which will be used for debt reduction or other corporate purposes. As a result of the transaction, the Company expects to record a gain on the sale. For business segment reporting purposes, Black Hills Energy Resources is included in the Energy marketing and transportation segment.

Revenues and net assets of the crude oil marketing and transportation business at December 31 are as follows (in thousands):

	2005	2004	2003
Revenues	$ 778,102	$ 636,572	$ 652,724
Operating income	$ 4,084	$ 7,583	$ 4,416

	2005	2004
Current assets	$ 94,697	$ 58,564
Property, plant and equipment	25,411	24,208
Other non-current assets	2,096	2,143
Current liabilities	(89,750)	(51,493)
Other non-current liabilities	(3,068)	(2,841)
Net assets	$ 29,386	$ 30,581

In conjunction with the sale of the operating assets of BHER, the $60.0 million uncommitted discretionary credit facility was terminated on March 1, 2006.

Acquisition

On March 6, 2006, the Company entered into a definitive agreement to acquire certain oil and gas assets of Koch Exploration Company, LLC. The assets include approximately 40 Bcfe of proved reserves, which are substantially all natural gas, and associated midstream and gathering assets. The acquisition is subject to further due diligence and is expected to close in the first quarter of 2006.

(25) OIL AND GAS RESERVES AND RELATED FINANCIAL DATA (Unaudited)

Black Hills Exploration and Production has operating and non-operating interests in 1,022 oil and gas properties in eleven states and holds leases on approximately 323,000 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):

	2005	2004	2003
Acquisition of properties:			
Proved	$ 4,110	$ 1,578	$ 21,075
Unproved	6,779	231	19,994
Exploration costs	7,194	6,094	4,089
Development costs	58,669	39,258	19,377
Company's share of equity method investees' costs of property acquisition, exploration and development	2,692	392	1,067
	$ 79,444	$ 47,553	$ 65,602

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, 2005, 2004 and 2003, 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 inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

	2005		2004		2003	
	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	5,239	141,983	5,389	124,062	4,880	28,513
Production	(396)	(10,854)	(432)	(9,456)	(405)	(8,548)
Additions	1,548	21,756	685	65,965	364	91,736
Property sales	—	—	(39)	(1,698)	—	—
Revisions to previous estimates	444	(24,312)	(364)	(36,890)	550	12,361
Balance at end of year	6,835	128,573	5,239	141,983	5,389	124,062
Proved developed reserves at end of year included above	4,694	80,959	4,608	80,366	4,830	66,294
Year-end prices (NYMEX)	$ 61.04	$ 11.23	$ 43.45	$ 6.15	$ 32.52	$ 6.19
Year-end prices (average well-head)	$ 58.52	$ 9.06	$ 41.19	$ 5.55	$ 30.56	$ 4.63

The 2005 reserve reconciliation reflected a 21.6 Bcfe downward revision to previous estimates. These downward revisions are primarily associated with the drilling and completion activities in the East Blanco Field, New Mexico. Approximately 60 percent of the downward revisions were primarily attributed to lower than expected production results from drilling activities conducted to further delineate the boundaries of the field. The lower reserves from the delineation wells, in turn, prompted revisions to previous reserve estimates (proved undeveloped and proved non-producing) for properties offsetting the delineation wells drilled in 2005.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31, (in thousands):

	2005	2004	2003
Unproved oil and gas properties	$ 15,390	$ 20,148	$ 22,705
Proved oil and gas properties	271,881	209,748	162,116
	287,271	229,896	184,821
Accumulated depreciation, depletion & amortization and valuation allowances	(85,488)	(75,870)	(61,928)
Net capitalized costs	$ 201,783	$ 154,026	$ 122,893
Company’s share of equity method investees’ net capitalized costs	$ 4,151	$ 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):

	2005	2004	2003
Revenues			
Sales	$ 87,235	$ 57,869	$ 43,458
Production costs	23,897	19,991	14,432
Depreciation, depletion & amortization and valuation provisions	20,396	11,497	9,331
	44,293	31,488	23,763
Income tax expense	10,412	5,342	3,953
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 32,530	$ 21,039	$ 15,742
Company’s share of equity method investees’ results of operations for producing activities	$ 692	$ (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):

	2005	2004	2003
Future cash inflows	$ 1,655,378	$ 1,044,098	$ 794,555
Future production and development costs	(586,829)	(409,478)	(339,732)
Future income tax expense	(324,306)	(144,053)	(129,538)
Future net cash flows	744,243	490,567	325,285
10 percent annual discount for estimated timing of cash flows	(346,774)	(181,368)	(123,163)
Standardized measure of discounted future net cash flows	$ 397,469	$ 309,199	$ 202,122

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):

	2005	2004	2003
Standardized measure – beginning of year	$ 309,199	$ 202,122	$ 72,318
Sales and transfers of oil and gas produced, net of production costs	(70,400)	(45,266)	(29,026)
Net changes in prices and production costs	301,055	55,916	51,735
Extensions, discoveries and improved recovery, less related costs	71,544	168,516	9,064
Net changes in future development costs	(4,302)	21,852	32,757
Revisions of previous quantity estimates	(185,878)	(96,419)	26,632
Accretion of discount	39,445	26,534	9,417
Net change in income taxes	(77,306)	(22,028)	(41,372)
Purchases of reserves	14,112	4,062	70,597
Sales of reserves	—	(6,090)	—
Standardized measure – end of year	$ 397,469	$ 309,199	$ 202,122

(26) 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 2005 and 2004.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2005				
Operating revenues	$ 296,019	$ 309,443	$ 373,011	$ 413,171
Operating income (loss)	35,529	34,175	(30,505)	46,737
Income (loss) from continuing operations	16,752	16,040	(23,650)	26,618
Loss from discontinued operations, net of taxes	(1,012)	(1,070)	(253)	(5)
Net income (loss)	15,740	14,970	(23,903)	26,613
Net income (loss) available for common stock	15,661	14,890	(23,903)	26,613
Earnings (loss) per common share:				
Basic -				
Continuing operations	$ 0.52	$ 0.49	$ (0.72)	$ 0.80
Discontinued operations	(0.03)	(0.03)	(0.01)	—
Total	$ 0.49	$ 0.46	$ (0.73)	$ 0.80
Diluted -				
Continuing operations	$ 0.51	$ 0.48	$ (0.72)	$ 0.79
Discontinued operations	(0.03)	(0.03)	(0.01)	—
Total	$ 0.48	$ 0.45	$ (0.73)	$ 0.79
Dividends paid per share	$ 0.32	$ 0.32	$ 0.32	$ 0.32
Common stock prices				
High	$ 33.32	$ 38.15	$ 43.50	$ 44.63
Low	$ 29.19	$ 32.63	$ 36.85	$ 33.67

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
		(in thousands, except per share amounts, dividends and common stock prices)						
2004								
Operating revenues	$	265,873	$	268,937	$	270,159	$	277,146
Operating income		30,145		26,570		38,307		41,231
Income from continuing operations		11,778		9,721		18,604		21,087
(Loss income from discontinued operations, net of taxes		(1,992)		1,794		(1,424)		(1,595)
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 (loss) per common share:								
Basic -								
Continuing operations	$	0.36	$	0.30	$	0.57	$	0.65
Discontinued operations		(0.06)		0.05		(0.04)		(0.05)
Total	$	0.30	$	0.35	$	0.53	$	0.60
Diluted -								
Continuing operations	$	0.36	$	0.30	$	0.56	$	0.64
Discontinued operations		(0.06)		0.05		(0.04)		(0.05)
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

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, 2005. 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 80 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 24, 2006.

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 24, 2006.

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 24, 2006.

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 24, 2006.

ITEM 14. PRINCIPAL ACCOUNTANT 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 24, 2006.

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, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, management's assessment of the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2005, and the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2005, and have issued our reports thereon dated March 13, 2006; such consolidated financial statements and reports are included in your 2005 Annual Report on Form 10-K and included elsewhere in this 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 13, 2006

(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, 2005, 2004 and 2003.

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 our consolidated financial statements and notes thereto.

BLACK HILLS CORPORATION
SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

		Additions			
Description	Balance at beginning of year	Charged to costs and expenses	Other (a)	Deductions (b)	Balance at end of year
		(in thousands)			
Allowance for doubtful accounts:					
2005	$ 4,196	$ (277)	$ 1,778	$ (1,012)	$ 4,685
2004	6,726	803	—	(3,333)	4,196
2003	2,571	1,337	3,002	(184)	6,726

(a) Recoveries
(b) Uncollectible accounts written off

3. Exhibits

Exhibit Number	Description
2.1*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as Exhibit 2 to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant's Form 10-K for 2004).
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).
3.3*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on December 26, 2000).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*	Coal Leases between Wyodak Resources Development Corp. and the Federal Government –Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) –Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) –Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.2*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between Wyodak Resources Development Corp. and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.3*	Rate Freeze Extension (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1999).
10.4*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).

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).
10.6*†	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1997).
10.7*†	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant's Form 10-K for 2000).
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).
10.9*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005).
10.10*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 11, 2005).
10.11*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 11, 2005).
10.12*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on July 11, 2005).
10.13*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on July 11, 2005).
10.14*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.15*†	Change in Control Agreement dated June 30, 2005 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 1, 2005).
10.16*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 1, 2005).
10.17*†	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1997). First Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2003). Second Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.14 to the Registrant's Form 10-K for 2003). Third Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 2, 2005).
10.18*†	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1999).
10.19*†	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Daniel P. Landguth as employee (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on December 23, 2002).

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* Credit Agreement, dated as of May 5, 2005 among Black Hills Corporation, as Borrower, the financial institutions from time to time party thereto as Banks, U.S. Bank, National Association, as Co-Syndication Agent, Union Bank of California, N.A., as Co-Syndication Agent, BANK OF AMERICA, N.A., as Co-Documentation Agent, BANK OF MONTREAL dba HARRIS NESBITT, as Co-Documentation Agent, and ABN AMRO Bank N.V. as Administrative Agent (filed as Exhibit 10.1 to the Registrant’s Form 10-Q for March 31, 2005).

10.23* 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).

10.24* First Amendment to the Amended and Restated Credit Agreement made as of the 30th day of September, 2004, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on October 6, 2004).

10.25* Second Amendment to the Amended and Restated Credit Agreement made as of the 5th day of April, 2005, among Enserco Energy Inc. the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.1 to the Registrant’s Form 10-Q for September 30, 2005).

10.26* Third Amendment to the Amended and Restated Credit Agreement made as of the 20th day of July 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.2 to the Registrant’s Form 10-Q for September 30, 2005).

10.27* Fourth Amendment to the Amended and Restated Credit Agreement made as of the 30th day of September, 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.3 to the Registrant’s Form 10-Q for September 30, 2005).

10.28 Fifth Amendment to the Amended and Restated Credit Agreement made as of the 30th day of November, 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale and UFJ Bank Limited.

10.29*	Stock Purchase Agreement between Xcel Energy, Inc., as “Seller” and Black Hills Corporation, as “Buyer,” dated January 13, 2004 (filed as Exhibit 2.1 to the Registrant’s Form 10-Q for March 31, 2004).
10.30*	Agreement for Lease between Wygen Funding, Limited Partnership and Black Hills Generation, Inc. dated as of July 20, 2001 (filed as Exhibit 10.31 to the Registrant’s Form 10-K for 2001).
10.31*	Amendment No. 1 dated as of December 20, 2001 to Agreement for Lease dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Owner and Black Hills Generation, Inc., as Agent (filed as Exhibit 10.32 to the Registrant’s Form 10-K for 2001).
10.32*	Lease Agreement dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Lessor and Black Hills Generation, Inc. as Lessee (filed as Exhibit 10.33 to the Registrant’s Form 10-K for 2001).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors’ Consent.
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.

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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.

(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, Chairman, President and
Chief Executive Officer

Dated: March 16, 2006

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, Chairman, President and Chief Executive Officer	Director and Principal Executive Officer	March 16, 2006
/S/ MARK T. THIES Mark T. Thies, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	March 16, 2006
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 16, 2006
/S/ JACK W. EUGSTER Jack W. Eugster	Director	March 16, 2006
/S/ JOHN R. HOWARD John R. Howard	Director	March 16, 2006
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 16, 2006
/S/ RICHARD KORPAN Richard Korpan	Director	March 16, 2006
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	March 16, 2006
/S/ WILLIAM G. VAN DYKE William G. Van Dyke	Director	March 16, 2006
/S/ JOHN B. VERING John B. Vering	Director	March 16, 2006
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 16, 2006

INDEX TO EXHIBITS

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2.1*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as Exhibit 2 to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant's Form 10-K for 2004).
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).
3.3*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on December 26, 2000).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*	Coal Leases between Wyodak Resources Development Corp. and the Federal Government –Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) –Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) –Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) –Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).

10.2*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between Wyodak Resources Development Corp. and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.3*	Rate Freeze Extension (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1999).
10. 4*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).
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).
10.6*†	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1997).
10.7*†	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant's Form 10-K for 2000).
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).
10.9*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005).
10.10*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 11, 2005).
10.11*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 11, 2005).
10.12*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on July 11, 2005).
10.13*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on July 11, 2005).
10.14*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).

10.15*†	Change in Control Agreement dated June 30, 2005 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on July 1, 2005).
10.16*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on July 1, 2005).
10.17*†	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant’s Form 10-K for 1997). First Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.13 to the Registrant’s Form 10-K for 2003). Second Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.14 to the Registrant’s Form 10-K for 2003). Third Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on June 2, 2005).
10.18*†	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant’s Form 10-K for 1999).
10.19*†	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Daniel P. Landguth as employee (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on December 23, 2002).
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*	Credit Agreement, dated as of May 5, 2005 among Black Hills Corporation, as Borrower, the financial institutions from time to time party thereto as Banks, U.S. Bank, National Association, as Co-Syndication Agent, Union Bank of California, N.A., as Co-Syndication Agent, BANK OF AMERICA, N.A., as Co-Documentation Agent, BANK OF MONTREAL dba HARRIS NESBITT, as Co-Documentation Agent, and ABN AMRO Bank N.V. as Administrative Agent (filed as Exhibit 10.1 to the Registrant’s Form 10-Q for March 31, 2005).
10.23*	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).

10.24* First Amendment to the Amended and Restated Credit Agreement made as of the 30th day of September, 2004, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 6, 2004).

10.25* Second Amendment to the Amended and Restated Credit Agreement made as of the 5th day of April, 2005, among Enserco Energy Inc. the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.1 to the Registrant's Form 10-Q for September 30, 2005).

10.26* Third Amendment to the Amended and Restated Credit Agreement made as of the 20th day of July 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.2 to the Registrant's Form 10-Q for September 30, 2005).

10.27* Fourth Amendment to the Amended and Restated Credit Agreement made as of the 30th day of September, 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, document agent and collateral agent, BNP Paribas, U.S. Bank National Association and Societe Generale, and each other financial institution which became a party thereto (filed as Exhibit 10.3 to the Registrant's Form 10-Q for September 30, 2005).

10.28 Fifth Amendment to the Amended and Restated Credit Agreement made as of the 30th day of November, 2005, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, U.S. Bank National Association, Societe Generale and UFJ Bank Limited.

10.29* Stock Purchase Agreement between Xcel Energy, Inc., as "Seller" and Black Hills Corporation, as "Buyer," dated January 13, 2004 (filed as Exhibit 2.1 to the Registrant's Form 10-Q for March 31, 2004).

10.30* Agreement for Lease between Wygen Funding, Limited Partnership and Black Hills Generation, Inc. dated as of July 20, 2001 (filed as Exhibit 10.31 to the Registrant's Form 10-K for 2001).

10.31* Amendment No. 1 dated as of December 20, 2001 to Agreement for Leasedated as of July 20, 2001 between Wygen Funding, Limited Partnership asOwner and Black Hills Generation, Inc., as Agent (filed as Exhibit 10.32 tothe Registrant's Form 10-K for 2001).

10.32* Lease Agreement dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Lessor and Black Hills Generation, Inc. as Lessee (filed as Exhibit 10.33 to the Registrant's Form 10-K for 2001).

21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors’ Consent.
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.

FIFTH AMENDMENT TO CREDIT AGREEMENT

THIS FIFTH AMENDMENT TO CREDIT AGREEMENT (this "Amendment") made as of the 30th day of November, 2005, among **ENSERCO ENERGY INC.**, a South Dakota corporation (the "Borrower"), **FORTIS CAPITAL CORP.** ("Fortis"), a Connecticut corporation, as a Bank, an Issuing Bank and as Administrative Agent, Documentation Agent and Collateral Agent for the Banks, **BNP PARIBAS** ("BNP Paribas"), a bank organized under the laws of France, as an Issuing Bank and a Bank, **U.S. BANK NATIONAL ASSOCIATION** ("U.S. Bank"), a national banking association, as a Bank and **SOCIETE GENERALE** ("SocGen"), a bank organized under the laws of France, as a Bank, and **UFJ BANK LIMITED, NEW YORK BRANCH** ("UFJ"), a bank organized under the laws of Japan, as a Bank, (collectively, the "Banks").

WHEREAS, the Borrower and the Banks have entered into an Amended and Restated Credit Agreement effective as of May 14, 2004 (as amended, the "Credit Agreement");

WHEREAS, the Borrower has requested that the Banks extend the Expiration Date and make certain additional changes to the Credit Agreement, and the Banks have agreed to make such changes; and

WHEREAS, UFJ is prepared to join the Credit Agreement as a Bank;

NOW, THEREFORE, in consideration of the premises herein contained and other good and valuable consideration, the sufficiency of which is hereby acknowledged, the parties hereto, intending to be legally bound, agree as follows:

1. **Defined Terms**. All capitalized terms used but not otherwise defined in this Amendment shall have the meaning ascribed to them in the Credit Agreement. Unless otherwise specified, all section references herein refer to sections of the Credit Agreement.

2. **Amendments to Credit Agreement**. The Credit Agreement is amended as follows:

(a) **The Definition of Advance Line Limit**. The definition of "Advance Line Limit" is amended to read as follows:

"'Advance Line Limit' means $50,000,000.00."

(b) **<u>The Definition of Borrowing Base Sub-Cap</u>**. The definition of "Borrowing Base Sub-Cap" is amended and restated to read as follows:

"'<u>Borrowing Base Sub-Cap</u>' means, on the Closing Date, an amount equal to $200,000,000.00; <u>provided</u>, <u>however</u>, Borrower may elect to change such Borrowing Base Sub-Cap five (5) times during any twelve (12) month period to be any of $100,000,000.00, $125,000,000.00, $150,000,000.00, $175,000,000.00 or $200,000,000.00 (provided that, regardless of any Elected Performance L/C Cap, the Borrowing Base Sub-Cap shall never exceed $200,000,000.00), which modified Borrowing Base Sub-Cap shall continue in effect until again changed by Borrower in accordance with this Agreement, or until automatically reduced as hereinafter set forth. Notwithstanding the foregoing, Borrower may not elect a Borrowing Base Sub-Cap unless Borrower's Net Working Capital and Tangible Net Worth at the time of election are greater than, or equal to, the amounts specified below:

(a) If Borrower elects $200,000,000.00, Borrower's Net Working Capital and Tangible Net Worth must each be at least $37,375,000.00 plus an amount equal to 30% of the Elected Performance L/C Cap;

(b) If Borrower elects $175,000,000.00, Borrower's Net Working Capital and Tangible Net Worth must each be at least $32,375,000.00 plus an amount equal to 30% of the Elected Performance L/C Cap;

(c) If Borrower elects $150,000,000.00, Borrower's Net Working Capital and Tangible Net Worth must each be at least $27,750,000 plus an amount equal to 30% of the Elected Performance L/C Cap; or

(d) If Borrower elects $125,000,000.00, Borrower's Net Working Capital and Tangible Net Worth must each be at least $23,125,000 plus an amount equal to 30% of the Elected Performance L/C Cap; or

(e) If Borrower elects $100,000,000.00, Borrower's Net Working Capital and Tangible Net Worth must each be at least

$18,500,000 plus an amount equal to 30% of the Elected Performance L/C Cap.

Borrower shall elect which Borrowing Base Sub-Cap is in effect from time to time by delivering to Agent and Banks a written notice of such election in the form of Exhibit I which is attached hereto. In the event that after Borrower makes a Borrowing Base Sub-Cap election Borrower's Net Working Capital or Tangible Net Worth as reflected on a Compliance Certificate delivered to Agent are not in compliance with the requirements set forth above, the Borrowing Base Sub-Cap shall be automatically reduced to the appropriate level set forth above to cause compliance with the requirements set forth above, provided that if Borrower fails to qualify for (a), (b), (c), (d) or (e) or fails to elect a Borrowing Base Sub-Cap, then the Borrowing Base Sub-Cap shall be $100,000,000.00. Such reduction shall take place upon Agent's receipt of such Compliance Certificate or notice of election. **NOTWITHSTANDING THE FOREGOING, BORROWER MAY NOT ELECT A BORROWING BASE SUB-CAP IN AN AMOUNT IN EXCESS OF THE THEN TOTAL UNCOMMITTED LINE AMOUNT SUBSCRIBED AS SET FORTH ON SCHEDULE 2.01 FROM TIME TO TIME.**"

(c) **The Definition of Economic Basis**. The following definition of "Economic Basis" is added to Section 1.01 (Definitions) of the Credit Agreement:

"'Economic Basis' means the calculation of financial accounting terms using mark to market of certain assets and liabilities as if the accounting standards of the Emerging Issues Task Force (EITF) under EITF-98-10 (accounting for contracts involved in energy trading and risk management activities) applied."

(d) **The Definition of Expiration Date**. Clause (a) in the definition of "Expiration Date" is amended to read as follows:

"(a) November 30, 2006."

(e) **The Definition of L/C Sub-Limit Cap**. Clause (c) and (e) of the definition of "L/C Sub-Limit Cap" is amended to read as follows:

"(a) Performance L/Cs - $15,000,000.00 but not to exceed the Elected Performance L/C Cap then in effect;

(b) Natural Gas/Transportation L/Cs - $40,000,000.00;

(c) Ninety (90) Day Swap L/Cs - $50,000,000.00;

(d) Three Hundred Sixty-Five (365) Day Swap L/Cs - $25,000,000.00;

(e) Natural Gas/Supply L/Cs - $200,000,000.00 less any amounts outstanding under (a), (b), (c) or (d) above."

(f) **The Definition of Maturity Date**. The definition of "Maturity Date" is amended to read as follows:

"'Maturity Date' means November 30, 2007."

(g) **Section 1.03 (Accounting Principles)**. Section 1.03(a) is amended by changing the period following the word "applied" on line three to a comma, and adding the following:

"except for the financial computations relating to the terms 'Net Working Capital' and 'Tangible Net Worth' which are to be made on an Economic Basis."

(h) **Schedule 2.01 (Uncommitted Line and Uncommitted Line Portions)**. Schedule 2.01 is deleted and replaced with Schedule 2.01 attached to this Amendment.

(i) **Section 7.01 (Financial Statements)**. Subsection (b) is deleted, and the following Subsections are added to Section 7.01:

"(b) as soon as available, but not later than 120 days after the end of each fiscal year, a copy of the financial statements of Borrower to include a balance sheet as at the end of such year and the related statements of income or operations, members' equity and cash flows for such year, in each case prepared on an Economic Basis and accompanied by a special purpose report acceptable to the Banks issued by a nationally-recognized independent accounting firm; and

(c) as soon as available, but not later than forty-five (45) days after the end of each month, Borrower-prepared financial statements prepared in accordance with GAAP and on an Economic Basis and accompanied by an explanation of any discrepancy between such statements resulting from the differing methods of preparation."

3. **Joinder Agreement**. As of the Effective Date (defined below), UFJ shall become a party to the Credit Agreement as a Bank, shall acquire all of the rights, powers and obligations of a Bank under the Credit Agreement, and shall have an Uncommitted Line Portion equal to $10,000,000. From and after the Effective Date, all references to "Banks" in the Credit Agreement and the other Loan Documents shall be deemed to include, in any event, UFJ.

4. **Effectiveness of Amendment.** This Amendment shall be effective on November 30, 2005 (the "Effective Date") upon receipt by the Agent of the following:

(a) An executed copy of this Amendment;

(b) Amended and restated promissory notes in favor of Fortis and SocGen and a new promissory note in favor of UFJ in the amount of their respective revised Uncommitted Line Portions;

(c) Payment of all fees and expenses owing to the Banks; and

(d) Such other documents and instruments as any Bank may reasonably request to reflect the changes set forth in this Amendment.

5. **Ratifications, Borrower Representations and Warranties.**

(a) The terms and provisions set forth in this Amendment shall modify and supersede all inconsistent terms and provisions set forth in the Credit Agreement and, except as expressly modified and superseded by this Amendment, the terms and provisions of the Credit Agreement are ratified and confirmed and shall continue in full force and effect. The Borrowers and the Banks agree that the Credit Agreement and the Loan Documents, as amended hereby, shall continue to be legal, valid, binding and enforceable in accordance with their respective terms.

(b) To induce the Banks to enter into this Amendment, the Borrower ratifies and confirms each representation and warranty set forth in the Credit Agreement as if such representations and warranties were made on the even date herewith, and further represents and warrants (i) that there has occurred since the date of the last financial statements delivered to the Banks no event or circumstance that has resulted or could reasonably be expected to result in a Material Adverse Effect, (ii) that no Event of Default exists on the date hereof, and (iii) that the Borrower is fully authorized to enter into this Amendment. THE BORROWER ACKNOWLEDGES THAT THE CREDIT AGREEMENT PROVIDES FOR A CREDIT FACILITY THAT IS COMPLETELY DISCRETIONARY ON THE PART OF THE BANKS AND THAT THE BANKS HAVE ABSOLUTELY NO DUTY OR OBLIGATION TO ADVANCE ANY REVOLVING LOAN OR TO ISSUE ANY LETTER OF CREDIT. THE BORROWER REPRESENTS AND WARRANTS TO THE BANKS THAT THE BORROWER IS AWARE OF THE RISKS ASSOCIATED WITH CONDUCTING BUSINESS UTILIZING AN UNCOMMITTED FACILITY.

6. **Benefits**. This Amendment shall be binding upon and inure to the benefit of the Banks and Borrower, and their respective successors and assigns; provided, however, that Borrowers may not, without the prior written consent of the Banks, assign any rights, powers, duties or obligations under this Amendment, the Credit Agreement or any of the other Loan Documents.

7. **Construction**. This Amendment shall be governed by and construed in accordance with the laws of the State of New York.

8. **Invalid Provisions**. If any provision of this Amendment is held to be illegal, invalid or unenforceable under present or future laws, such provision shall be fully severable and the remaining provisions of this Amendment shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance.

9. **Entire Agreement**. The Credit Agreement, as amended by this Amendment, contains the entire agreement among the parties regarding the subject matter hereof and supersedes all prior written and oral agreements and understandings among the parties hereto regarding same.

10. **Reference to Credit Agreement**. The Credit Agreement and any and all other agreements, documents or instruments now or hereafter executed and delivered pursuant to the terms hereof or pursuant to the terms of the Credit Agreement, as amended hereby, are hereby amended so that any reference in the Credit Agreement to the Credit Agreement shall mean a reference to the Credit Agreement as amended hereby.

11. **Counterparts**. This Amendment may be separately executed in any number of counterparts, each of which shall be an original, but all of which, taken together, shall be deemed to constitute one and the same agreement.

[The Remainder of this Page Intentionally Left Blank]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers as of the day and year first above written.

ENSERCO ENERGY INC.,
a South Dakota corporation

By:___________________________________
Name:_________________________________
Title:___________________________________

350 Indiana Street, Suite 400
Golden, Colorado 80401
Attention: Thomas M. Ohlmacher
Telephone: (303) 568-3261
Facsimile: (303) 568-3250

FORTIS CAPITAL CORP.,
as Agent

By: ___________________________________
Name: ________________________________
Title: __________________________________

By: ___________________________________
Name: ________________________________
Title: __________________________________

15455 North Dallas Parkway
Suite 1400
Addison, TX 75001
Attention: Irene C. Rummel
Telephone: (214) 953-9313
Facsimile: (214) 969-9332

FORTIS CAPITAL CORP.,
as a Bank and an Issuing Bank

By: ______________________________
Name: ______________________________
Title: ______________________________

By: ______________________________
Name: ______________________________
Title: ______________________________

15455 North Dallas Parkway
Addison, TX 75001
Attention: Irene C. Rummel
Telephone: (214) 953-9313
Facsimile: (214) 969-9332

BNP PARIBAS,
as an Issuing Bank and a Bank

By:______________________________
Name:______________________________
Title: ______________________________

By:______________________________
Name:______________________________
Title: ______________________________

787 Seventh Avenue
New York, NY 10019
Attention: Keith Cox
Phone: (212) 841-2575
Fax: (212) 841-2536

U.S. BANK NATIONAL ASSOCIATION,
as a Bank

By:____________________________________
Name:_________________________________
Title:___________________________________

918 17th Street
DNCOBB3E
Denver, CO 80202
Attn: Monte Deckerd
Phone: (303) 585-4212
Fax: (303) 585-4362

SOCIETE GENERALE,
as a Bank

By:____________________________________
Name:_________________________________
Title:___________________________________

By:____________________________________
Name:_________________________________
Title:___________________________________

1221 Avenue of the Americas
New York, NY 10020
Attn: Barbara Paulsen
Phone: (212) 278-6496
Fax: (212) 278-7953

UFJ BANK LIMITED, NEW YORK BRANCH,
as a Bank

By:____
Name:______________________________________
Title:______________________________________

55 East 52nd Street
New York, NY 10055
Attention: Chan Park
Phone: (212) 339-6261
Fax: (212) 754-2360

SCHEDULE 2.01

UNCOMMITTED LINE AND
UNCOMMITTED LINE PORTIONS
(EXCLUDING SWAP CONTRACTS)

I. Uncommitted Line:

A. Maximum Line: $200,000,000.00

B. Total Line Amount Subscribed: $200,000,000.00

C. Subscribed Percentage: 100%

II. Uncommitted Line Portions:

A. Subscribed Amounts:

Bank	Dollar Amount	Pro Rata Share
Fortis Capital Corp.	$75,000,000.00	37.500000%
BNP Paribas	$55,000,000.00	27.500000%
Societe Generale	$45,000,000.00	22.500000%
U.S. Bank	$15,000,000.00	7.500000%
UFJ Bank Limited	$10,000,000.00	5.000000%
Total Subscribed Line Portions	$200,000,000.00	100%

III. Advance Line Limit: $ 50,000,000.00

IV. L/C Line Limit (Subscribed Percentage, times $200,000,000.00) $200,000,000.00

Effective Date: November 30, 2005

Exhibit 21

BLACK HILLS CORPORATION

SUBSIDIARIES
December 31, 2005

Black Hills Artesia, LLC, a Delaware limited liability company

Black Hills Cabresto Pipeline, LLC, a Delaware limited liability company

Black Hills Colorado, LLC, a Delaware limited liability company

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 Energy, Inc., a South Dakota corporation

Black Hills Exploration and Production, Inc., a Wyoming 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 GP, LLC, a Delaware limited liability company

Black Hills Ivanpah, 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 Midstream, LLC, a South Dakota limited liability company

Black Hills Millennium Pipeline, Inc., a South Dakota corporation

Black Hills Millennium Terminal, Inc., a South Dakota corporation

Black Hills Nevada Operations, LLC, a Delaware limited liability company

Black Hills Nevada Real Estate Holdings, LLC, a Delaware limited liability company

Black Hills Nevada, LLC, a Delaware limited liability company

Black Hills Ocotillo, 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 limited liability company

Black Hills Plateau Production, LLC, a Delaware limited liability company

Black Hills Power, Inc., a South Dakota corporation

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 Waterville Station, LLC, a South Dakota limited liability company

Black Hills Wyoming, Inc., a Wyoming corporation

Buick Power, LLC, a Delaware limited liability company

Cheyenne Light, Fuel and Power Company, a Wyoming corporation

Daksoft, Inc., a South Dakota corporation

Desert Arc I, L.L.C., a Delaware limited liability company

Desert Arc II, L.L.C., 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, L.L.C., a Delaware limited liability company

Harbor Cogeneration Company, LLC, a Delaware limited liability company

Las Vegas Cogeneration Energy Financing Company, L.L.C., a Delaware limited liability company

Las Vegas Cogeneration II, L.L.C., 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

Sunco, Ltd., a Limited Liability Company, a Nevada limited liability company

Varifuel, LLC, a South Dakota limited liability company

West Cascade Energy, LLC, a Delaware limited liability company

Wyodak Resources Development Corp., a Delaware corporation

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, 333-63264 and 333-125697 on Form S-8 of Black Hills Corporation of our reports dated March 13, 2006, 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 Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities*, effective January 1, 2003, and Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities,* effective December 31, 2003), and management's report on 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, 2005.

Minneapolis, Minnesota
March 13, 2006

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, 333-63264 and 333-125697 and the Registration Statements on Form S-3, Nos. 33-71130 and 333-101541.

RALPH E. DAVIS ASSOCIATES, INC.

Houston, Texas
March 8, 2006

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, 2006

/s/ David R. Emery
Chairman, 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, 2006

/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, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, Chairman, 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, 2006

/s/ David R. Emery
David R. Emery
Chairman, 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, 2005 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, 2006

/s/ Mark T. Thies
Mark T. Thies
Executive Vice President and
Chief Financial Officer