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

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

For the fiscal year ended December 31, 2006

☐ 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 ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

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. ☒

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 ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

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

At June 30, 2006 $1,132,052,314

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 January 31, 2007
Common stock, $1.00 par value	33,406,299 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 2007 Annual Meeting of Stockholders to be held on May 22, 2007, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AFUDC	Allowance for Funds Used During Construction
Allegheny	Allegheny Energy Supply Company, LLC
AOCI	Accumulated Other Comprehensive Income
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
Aquila	Aquila, Inc.
ARO	Asset Retirement Obligations
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC Pension Plan	The Pension Plan of Black Hills Corporation
BHCCP	Black Hills Corporation Credit Policy
BHCRPP	Black Hills Corporation Risk Policies and Procedures
BHEC	Black Hills Energy Capital, Inc.
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Corporation Plan	Black Hills Corporation Retirement Savings Plan
Black Hills Energy	Black Hills Energy, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Generation	Black Hills Generation, Inc., a direct, wholly-owned subsidiary of Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Wyoming	Black Hills Wyoming, Inc., an indirect, wholly-owned subsidiary of Black Hills Energy, Inc.
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of the Company
Cheyenne Light Pension Plan	The Cheyenne Light, Fuel and Power Company Pension Plan
Cheyenne Light Plan	Cheyenne Light, Fuel and Power Company Retirement Savings Plan
CRPP	Commodity Risk Policies and Procedures
CT	Combustion turbine
Dth	Dekatherms
ECA	Electric Cost Adjustment
EITF	Emerging Issues Task Force
EITF 91-6	EITF No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts"
EITF 98-10	EITF Issue No. 98-10, "Accounting for Contracts involving Energy Trading and Risk Management Activities"
EITF 99-19	EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent"
EITF 02-3	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 03-11	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"
EITF 04-6	EITF Issue No. 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry"
EITF 04-13	EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with

	the Same Counterparty”
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Energy, Inc.
EPA	U. S. Environmental Protection Agency
EPA 2005	Energy Policy Act of 2005
ESPP	Employee Stock Purchase Plan
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 45	FASB Interpretation No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others”
FIN 46	FASB Interpretation No. 46, “Consolidation of Variable Interest Entities”
FIN 46(R)	FASB Interpretation No. 46, “Consolidation of Variable Interest Entities Revised”
FIN 48	FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement 109”
FSP	FASB Staff Position
FSP 123(R)-3	FSP No. FAS 123(R)-3, “Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards”
GAAP	Generally Accepted Accounting Principles
GCA	Gas Cost Adjustment
Great Plains	Great Plains Energy Incorporated
Indeck	Indeck Capital, Inc.
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Las Vegas I	Las Vegas I gas-fired power plant
Las Vegas II	Las Vegas II gas-fired power plant
MAPP	Mid-Continent Area Power Pool
Mbbl	Thousand barrels of oil
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Company
MEAN	Municipal Energy Agency of Nebraska
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody’s	Moody’s Investor Services, Inc.
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hour
NPC	Nevada Power Company
NPDES	National Pollutant Discharge Elimination System
PCBs	Polychlorinated Biphenyls
PPM	PPM Energy, Inc.
PSCo	Public Service Company of Colorado
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCRA	EPA Resource Conservation and Recovery Act
SCE	Southern California Edison
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 13	SFAS 13, “Accounting for Leases”
SFAS 69	SFAS 69, “Disclosures about Oil and Gas Producing Activities – an

	amendment of FASB Statements 19, 25, 33 and 39”
SFAS 71	SFAS 71, “Accounting for the Effects of Certain Types of Regulation”
SFAS 87	SFAS 87, “Employers’ Accounting for Pensions”
SFAS 106	SFAS 106, “Employer’s Accounting for Post-retirement Benefits Other Than Pensions”
SFAS 109	SFAS 109, “Accounting for Income Taxes”
SFAS 123	SFAS 123, “Accounting for Stock-Based Compensation”
SFAS 123(R)	SFAS 123 (Revised 2004), “Share-Based Payment”
SFAS 133	SFAS 133, “Accounting for Derivative Instruments and Hedging Activities”
SFAS 142	SFAS 142, “Goodwill and Other Intangible Assets”
SFAS 143	SFAS 143, “Accounting for Asset Retirement Obligations”
SFAS 144	SFAS 144, “Accounting for the Impairment of Long-lived Assets”
SFAS 157	SFAS 157, “Fair Value Measurements”
SFAS 158	SFAS 158, “Employer’s Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statements No. 87, 88, 106 and 132(R)”
SFAS 159	SFAS 159, “The Fair Value Option for Financial Assets and Financial Liabilities”
SO2	Sulfur Dioxide
S&P	Standard & Poor’s Rating Services
TSA	Transmission Service Agreement
VaR	Value-at-Risk
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corporation, a direct, wholly-owned subsidiary of Black Hills Energy, Inc.

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 SEC.

Safe Harbor for Forward-Looking Information

This Annual Report on Form 10-K includes "forward-looking statements" as defined by the 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 Item IA. of this Form 10-K and the following:

- Our ability to obtain adequate cost recovery for our retail utility operations through regulatory proceedings and receive favorable rulings in periodic applications to recover costs for fuel and purchased power in our regulated utilities;

- Our ability to complete acquisitions for which definitive agreements have been executed;

- Our ability to obtain regulatory approval of acquisitions which, even if approved, could impose financial and operating conditions or restrictions that could impact our expected results;

- Our ability to successfully integrate and profitably operate any future acquisitions;

- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;

- Our ability to successfully maintain or improve our corporate credit rating;

- Our ability to complete the permitting, construction, start up and operation of power generating facilities in a cost-effective and timely manner;

- Our ability to meet production targets for our oil and gas 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;

- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and actual future production rates and associated costs;

- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;

- The timing and extent of scheduled and unscheduled outages of power generation facilities;

- 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;

- Changes in business and financial reporting practices arising from the enactment of the Energy Policy Act of 2005;

- Our ability to remedy any deficiencies that may be identified in the review of our internal controls;

- The timing, volatility 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;

- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;

- Our ability to minimize defaults on amounts due from counterparties with respect to trading and other transactions;

- 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 or events;

- 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;

- General economic and political conditions, including tax rates or policies and inflation rates; 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 any such forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

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 services and wholesale energy.

Retail Services Group

Our retail services group conducts business in two segments:

Electric Utility. Through Black Hills Power, our electric utility segment, we engage in the generation, transmission and distribution of electricity to approximately 64,200 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. Through Cheyenne Light, our combination electric and gas utility segment, we engage in the distribution of electric and natural gas service and serve approximately 38,900 electric and 32,600 natural gas customers in Cheyenne, Wyoming and vicinity. We acquired Cheyenne Light on January 21, 2005.

Wholesale Energy Group

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

Oil and Gas. BHEP and its subsidiaries acquire, develop and produce natural gas and crude oil primarily in the Rocky Mountain region of the United States.

Power Generation. Black Hills Generation and its subsidiaries and Black Hills Wyoming engage in the production and sale of electric capacity and energy through a diversified portfolio of generating plants in the Rocky Mountain and Western regions of the United States.

Coal Mining. WRDC mines and sells coal at our coal mine located near Gillette, Wyoming.

Energy Marketing. Enserco is engaged in the marketing of natural gas and crude oil primarily in the Western and Mid-continent regions of the United States and in Canada.

Recent Events

On February 7, 2007, we announced that we have entered into definitive agreements to acquire Aquila’s electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa along with the associated liabilities for a total of $940 million in cash, subject to closing adjustments. This acquisition would significantly broaden our regional presence and retail utility base. The transaction would add a total of approximately 616,000 new utility customers (93,000 electric customers and 523,000 gas customers) to the 137,000 utility customers (104,000 electric customers and 33,000 gas customers) we currently serve. Other assets included in the transaction include a customer service center and centralized natural gas operation in Nebraska.

At the same time we entered into our agreements with Aquila, Aquila also entered into an agreement with Great Plains for the merger of Gregory Acquisition Corp., a subsidiary of Great Plains, with and into Aquila. Each transaction is contingent on the completion of the other transaction, meaning that one transaction will not be completed unless the other transaction is completed. Completion of the transactions is subject to various conditions, including: (i) approval of the FERC; (ii) approval of the Colorado Public Utilities Commission, Iowa Utilities Board, Kansas Corporation Commission, and Nebraska Public Service Commission; (iii) the expiration or early termination of any waiting period under the Hart-Scott-Rodino Antitrust Act of 1976, as amended; (iv) the absence of a material adverse effect on the utility businesses being sold to us; and (v) the ability and readiness of Aquila, Great Plains and Gregory Acquisition Corp. to complete the merger immediately after the completion of the asset sale transactions.

Segment Financial Information

Discussion of our business strategy as well as prospective information is included in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding the segments of Black Hills Corporation's business is incorporated herein by reference to Item 8 – Financial Statements and Supplementary Data, Note 20 to the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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.

Properties and Agreements

Electric Utility Segment

Our regulated 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 operating cash flows.

Distribution and Transmission. Black Hills Power's distribution and transmission businesses serve approximately 64,200 electric customers, with an electric transmission system of 447 miles of high voltage transmission lines (greater than 69 KV) and 420 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 91 percent of Black Hills Power's retail electric revenues in 2006 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, 2006 was comprised of 26 percent commercial, 21 percent residential, 13 percent contract wholesale, 22 percent wholesale off-system, 11 percent industrial and 7 percent municipal sales and other revenue. We provide service to approximately 84 percent of our large commercial and industrial customers 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 primarily in the WECC and MAPP regions.

- Black Hills Power is subject to regulation by the SDPUC, the WPSC and the MTPSC. Black Hills Power operated under two consecutive retail rate freezes in South Dakota that were imposed in 1995 and expired on January 1, 2005. The rate freezes preserved a low-cost rate structure for our retail customers at levels below the national average and insulated them from changes in fuel and purchased power costs but allowed Black Hills Power to retain the benefits from cost savings and from wholesale "off-system" sales, which were not covered by the rate freezes. On June 30, 2006, Black Hills Power filed a rate case with the SDPUC to increase retail rates for South Dakota customers and to add tariff provisions for automatic adjustment of rates for changes in energy, fuel and transmission costs. The cost adjustments would require Black Hills Power to absorb a portion of power cost increases, depending in part on earnings on certain short-term wholesale sales of electricity. On December 28, 2006, Black Hills Power received an order from the SDPUC approving a 7.8 percent increase in retail rates and the addition of tariff provisions for automatic adjustments, effective January 1, 2007. Absent certain conditions, the order also restricts Black Hills Power from requesting an increase in base rates that would go into effect prior to January 1, 2010.

- Black Hills Power owns 35 percent and Basin Electric owns 65 percent of a transmission tie that provides an interconnection between the Western and Eastern transmission grids, enabling access to both the WECC region in the West, and the 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 MW – 200 MW from West to East and 200 MW 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 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 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 MW 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.

- Black Hills Power has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the Western region from 2007 through 2023.

- Black Hills Power has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming to serve our power sales contract with MDU through 2016, 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, which expired on December 31, 2006, for the sale of up to 55 MW of capacity and energy to serve the Sheridan, Wyoming electric service territory. Our new power purchase agreement with MDU, effective January 1, 2007 through the end of 2016, will supply up to 74 MW of capacity and energy for Sheridan, Wyoming; and

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

We integrate these consumers into Black Hills Power's control area and consider them as part of our firm native load. Black Hills Power also provides 20 MW of energy and capacity to MEAN under a contract that expires in 2013. This contract is unit-contingent based on the availability of our Neil Simpson II plant.

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 MW 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 and reserve capacity contracts with PacifiCorp:

- a power purchase agreement expiring in 2023, involving the purchase by Black Hills Power of 50 MW of coal-fired baseload power; and

- a reserve capacity integration agreement expiring in 2012, which makes available to Black Hills Power 100 MW 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 415 MW in July 2006, with an average system load of 249 MW for the year ended December 31, 2006. None of Black Hills Power's generation is restricted by hours of operation, thereby providing 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 (MW)	Interest	Net Capacity (MW)	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 MW. This plant began service in 1960 and operates as a baseload plant. The plant purchases coal from our WRDC coal 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 MW. These plants began service in 1965 and operate as peaking plants.

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

Lange CT. The Lange CT is a wholly-owned 40 MW gas-fired plant located near Rapid City, South Dakota. The plant began 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 MW and began service in 1969. Neil Simpson II has a capacity of 91 MW and began service in 1995. These mine-mouth plants receive their coal directly from our WRDC coal mine via conveyor and operate as baseload facilities.

Neil Simpson CT. The Neil Simpson CT is a wholly-owned gas-fired plant located near Gillette, Wyoming with a capacity of 40 MW. This plant began service in 2000 and supplies peaking capabilities.

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

Wyodak. Wyodak is a 362 MW mine-mouth coal-fired plant owned 80 percent by PacifiCorp and 20 percent (or 72.4 net MW) by Black Hills Power. The WRDC coal mine furnishes all the coal fuel supply for the Wyodak plant. The plant, which is operated by PacifiCorp, began service in 1978 and operates as a baseload plant.

Rate Regulation. Rates for Black Hills Power’s retail electric service are subject to regulation by the SDPUC for customers in South Dakota, the WPSC for customers in Wyoming and the MTPSC for customers in Montana. Any changes in retail rates are subject to approval by the respective regulatory body. Two consecutive rate freezes granted by the SDPUC, which were 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. On June 30, 2006, Black Hills Power filed an application with the SDPUC for an increase in its electric rates for South Dakota customers and to provide automatic adjustment of rates for changes in energy, fuel and transmission costs. On December 28, 2006, the SDPUC approved a rate increase of 7.8 percent along with the addition of tariff provisions which provide for the automatic adjustment of rates. The rates and new tariff provisions are effective beginning January 1, 2007. Terms of the settlement agreement with the SDPUC include the following:

- Annual cost adjustments reflecting changes in the costs of both electric transmission and fuel delivered to coal-fired power generation will be allowed, with adjustments reflected in monthly customer billings commencing in March following the year on which the calculation was made;

- Annual cost adjustments reflecting changes in the cost of natural gas used in power generation and purchased power, with adjustments, if any, reflected in monthly customer billings commencing in March following the year on which the calculation was made. The Company also agreed to share in such cost increases, under certain circumstances while retaining the benefits from off-system sales; and

- No additional base rate increases, with certain exceptions, for a period of three years ending December 31, 2009.

Combination Electric and Gas Utility Segment

Electric System. Cheyenne Light's electric system serves approximately 38,900 customers in Cheyenne, Wyoming and vicinity, with a peak load of 163 MW and an average load of 112 MW. 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 MW of energy and capacity from our Gillette CT, until August 2011, and 60 MW of energy and capacity from our Wygen I plant until the first quarter of 2013. Cheyenne Light is also constructing a 90 MW coal-fired plant (Wygen II) adjacent to the WRDC coal mine near Gillette, Wyoming, which is expected to be in service by the end of 2007. On November 22, 2006, Cheyenne Light entered into a 20-year agreement to purchase power provided by a new wind generation facility to be located near the City of Cheyenne, Wyoming. The agreement is pending regulatory and other approvals and is anticipated to provide up to 30 MW of renewable power to Cheyenne Light beginning in early 2008.

Natural Gas System. Cheyenne Light's natural gas distribution system serves approximately 32,600 natural gas customers in the City of Cheyenne and other portions of Laramie County, Wyoming. Cheyenne Light's annual natural gas sales to commercial and residential customers for 2006 were approximately 4.4 million Dth. Cheyenne Light purchases natural gas from independent suppliers for delivery to its retail customers. The natural gas supplies arrive at our 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.

Rate Regulation. Cheyenne Light 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. All electric demand, purchased power and transmission costs are recoverable through an ECA clause subject to WPSC jurisdiction. All purchased gas and transportation costs are recoverable through a GCA clause, also subject to WPSC jurisdiction. Differences between actual costs incurred and costs recovered in rates are deferred and recovered or refunded through prospective adjustments to rates. These ECA and GCA filings are made at least annually and more frequently if there is a significant over or under-recovery of these costs. Rate changes for cost recovery require WPSC approval before going into effect. In October 2005, the WPSC approved a 3.65 percent and 5.11 percent increase in Cheyenne Light's base rates for gas and electric service, respectively, effective on January 1, 2006.

Business Characteristics

The following business characteristics are common within our Retail Services Group:

Competition. Historically, electric and gas utilities were established as natural monopolies operating in highly regulated environments where they were obligated to provide electric and gas services to their customers in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return. Recently, the structure of the utility industry has been subject to change as a result of increased merger and acquisition activity, resulting in blended utilities with objectives to capture economies of scale or establish a strategic niche in preparing for the future.

Competition in varying degrees exists for our retail services group. Established service territories still define our electric service area, but as the communities we serve continue to grow and expand, we encroach upon areas served by rural electric cooperatives. Our electric and gas utility faces some competition as some industrial and large customers have the ability to own or operate facilities to generate their own electricity. In addition, our electric utility competes with alternative forms of energy, such as natural gas. The primary factors we face in competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power.

Legislative and regulatory activity could affect our operations in the future, although we cannot predict the substance or timing of these initiatives. The efforts by state and federal governing bodies to restructure the electric utility industry have moderated. There have been no legislative actions regarding electric retail choice in any of the states in which we operate, and the Company does not expect retail competition in the foreseeable future.

Our electric utility, like the electric industry generally, faces competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, more generators may now participate in this market. The principal factors affecting competition for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

Regulation. We are subject to a broad range of federal, state and local energy and environmental laws and regulations, which significantly impact our business operations, including the following:

Energy Policy Act of 2005. EPA 2005 was signed into law on August 8, 2005. EPA 2005 repealed PUHCA 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.

Public Utility Holding Company Act of 1935. On December 28, 2004, we became a registered holding company under PUHCA. 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, human resources, information systems, engineering, financial, legal, maintenance and other services. With the passage of EPA 2005, PUHCA was repealed and the oversight of public utility holding companies was transferred to FERC effective February 8, 2006.

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 QFs. With the enactment of EPA 2005, state regulators must consider standards for regulated utilities related to net metering, fuel diversity, fossil fuel generation efficiency, smart metering and interconnection for distributed resources.

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 must 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 affiliates.

Environmental Regulation.

<u>PCBs</u>. Under the federal Toxic Substances Control Act, the EPA has issued regulations that control the use and disposal of 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.

Air Quality. Our Neil Simpson II, Neil Simpson CT, Lange CT, Wyodak and Wygen II plants are all subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold 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. For future plants, we plan to comply with the need for holding the appropriate number of allowances by reducing SO2 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 cost of obtaining the required number of allowances needed for future projects into our overall financial analysis of such projects.

Title V of the federal Clean Air Act dictates 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 have received permits.

In March 2005, the EPA issued mercury emission requirements for fossil-fuel-fired steam electric power plants. Neil Simpson II and Wyodak will be subject to the monitoring, cap and trade requirements beginning in 2010. Our air permit for Wygen II requires mercury removal, and therefore Wygen II is one of the first coal-fired plants to incorporate mercury reduction technology. Wygen II will be subject to “cap and trade” requirements beginning in 2010. There are several pending legal actions involving other parties, challenging various aspects of the mercury rule. Until these legal actions and emission control system evaluation efforts are finalized, we cannot fully evaluate the impact of mercury regulations on the operation of our facilities.

Solid Waste Disposal. Under appropriate state permits, we dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Ash and wastes from flue gas and sulfur removal from the Wyodak, Neil Simpson I, Ben French and Neil Simpson II plants are deposited in mined areas at the WRDC 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 would increase costs, which 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 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 can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages. Agreements in place require PacifiCorp to be responsible for any such costs related to the solid waste from its 80 percent interest in the Wyodak plant.

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 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. 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. We are aware of no proposed regulations that will have a significant impact on our operations. Additionally, the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations. All of our facilities regulated under this program have their required plans in place.

Seasonality. Our electric utility and electric and gas utility business segments are seasonal businesses, and weather patterns may impact their operating performance. Demand for electricity is often greater in the summer and winter months for cooling and heating, respectively. Because our electric utility has a diverse customer and revenue base and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are milder in the winter and cooler in the summer in comparison to other investor-owned utilities. Conversely, natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather patterns throughout our service territories, and as a result, a significant amount of natural gas revenues are normally recognized in the heating season of the first and fourth quarters.

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.

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.

Wholesale Energy Group

Our wholesale energy group, which operates through Black Hills Energy and its subsidiaries, produces and sells electric capacity and energy through ownership of a diversified portfolio of generating plants; we produce coal, natural gas and crude oil primarily in the Rocky Mountain region; and market and store natural gas and crude oil. The wholesale energy group consists of four business segments for reporting purposes:

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

Oil and Gas Segment

Our oil and gas segment, which operates through BHEP and its subsidiaries, acquires, explores, develops and produces natural gas and crude oil. As of December 31, 2006, we held operated interests in oil and gas properties totaling approximately 625 gross and 571 net 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 Julesberg Basin of Colorado and Nebraska. In our San Juan and Piceance Basin operations, we also own and operate natural gas gathering pipeline systems along with associated gas compression and treating facilities. We also hold non-operated interests in oil and natural gas properties totaling approximately 511 gross and 71 net 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 and associated gathering system located in Weston County, Wyoming. The plant is adjacent to our producing properties in that area, where BHEP production accounts for the majority of the facility throughput. The plant is operated by Anadarko, Inc.

At December 31, 2006, we had total reserves of approximately 199 Bcfe, of which natural gas comprised 83 percent of total reserves and oil comprised 17 percent of total reserves. The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region. Approximately 36 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 23 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties.

An expanding area of operated interests is in multiple fields of the Piceance Basin of Colorado, which now represents 35 percent of our total reserves, of which approximately 67 percent are undeveloped. 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 interests in the Plateau Field, Mesa County, Colorado. 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. On March 17, 2006, effective as of January 1, 2006, we acquired certain oil and gas assets of Koch Exploration Company, LLC, including approximately 40.0 Bcf 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 adjacent to the properties acquired from Red Oak in 2005, and is comprised of leases covering more than 31,000 gross and 18,000 net acres, of which more than 48 percent are presently undeveloped. The acquisition included 63 wells, of which 58 were operated by Koch Exploration Company. Finally, on August 17, 2006, effective as of April 1, 2006, we completed the acquisition from a third party of most of the remaining working interests associated with the property acquired from Koch Exploration Company. The acquisition included approximately 22.4 Bcf of proved reserves together with an interest in associated midstream and gathering assets. The acquisition included interests in leases covering more than 15,000 net acres.

Summary Oil and Gas Reserve Data

The following tables set forth summary information concerning our estimated proved developed and undeveloped oil and gas reserves and the 10 percent discounted present value of estimated future net revenues as of December 31 based on reports 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 Developed Reserves:	December 31, 2006			December 31, 2005		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	4,617	9,741	37,443	4,589	9,309	36,843
New Mexico	19	44,171	44,285	43	52,691	52,949
Colorado	—	23,052	23,052	—	7,684	7,684
Montana	41	3,953	4,199	24	2,972	3,116
Nebraska	—	1,810	1,810	—	5,391	5,391
Other states	46	5,164	5,440	38	2,912	3,140
Total Proved Developed Reserves	4,723	87,891	116,229	4,694	80,959	109,123

Proved Undeveloped Reserves:	December 31, 2006			December 31, 2005		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	997	1,474	7,456	2,135	1,326	14,136
New Mexico	—	26,653	26,653	—	43,950	43,950
Colorado	—	47,437	47,437	—	2,278	2,278
Montana	—	770	770	6	60	96
Nebraska	—	—	—	—	—	—
Other states	3	529	547	—	—	—
Total Proved Undeveloped Reserves	1,000	76,863	82,863	2,141	47,614	60,460

Total Proved Reserves:	December 31, 2006			December 31, 2005		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	5,614	11,215	44,899	6,724	10,635	50,979
New Mexico	19	70,824	70,938	43	96,641	96,899
Colorado	—	70,489	70,489	—	9,962	9,962
Montana	41	4,723	4,969	30	3,032	3,212
Nebraska	—	1,810	1,810	—	5,391	5,391
Other states	49	5,693	5,987	38	2,912	3,140
Total Proved Reserves	5,723	164,754	199,092	6,835	128,573	169,583

	December 31, 2006	December 31, 2005
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	58%	64%
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	42%	36%
Present value of estimated future net revenues, before tax (in thousands)	$ 338,521	$ 560,023

The following table reflects average wellhead pricing used in the determination of the present value of estimated future net revenues, before tax:

	December 31, 2006	December 31, 2005
Gas per Mcf	$ 5.34	$ 9.06
Oil per Bbl	$ 52.06	$ 58.52

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2006, we participated in drilling 106 gross (60.01 net) development and exploratory wells, with a success rate of approximately 95 percent. A development well is a well drilled within a proved area of a reservoir known to be productive. An exploratory well is a well drilled to find and/or produce oil or gas in an unproved area, to find a new reservoir in a previously productive field or to extend a known reservoir. Gross wells represent the total wells we participated in, regardless of ownership interest, with net wells representing our fractional ownership interests within those wells.

Year ended December 31,	2006		2005		2004	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	28.20	—	1.36	1.00	0.60	—
New Mexico	21.00	1.00	36.28	1.00	14.92	—
Montana	3.42	0.02	3.22	—	3.28	—
Nebraska	—	1.00	17.00	—	—	2.60
Other states	0.20	—	3.81	0.67	4.40	2.51
Total	52.82	2.02	61.67	2.67	23.20	5.11

Year ended December 31,	2006		2005		2004	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	0.04	—	0.10	—	0.06	—
New Mexico	1.00	—	0.80	—	—	—
Montana	2.35	0.50	3.74	0.68	7.32	0.31
Nebraska	—	—	—	0.50	5.00	1.00
Other states	1.28	—	0.57	0.15	1.48	—
Total	4.67	0.50	5.21	1.33	13.86	1.31

As of December 31, 2006, we were participating in the drilling of 34 gross (9.75 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, 2006:

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
Wyoming	4	—	4	1.09	—	1.09
New Mexico	38	6	44	35.86	5.79	41.65
Colorado	41	4	45	34.24	3.00	37.24
Montana	5	—	5	0.82	—	0.82
Nebraska	7	—	7	7.00	—	7.00
Other states	8	4	12	1.88	0.26	2.14
Total	103	14	117	80.89	9.05	89.94

Production

The following table presents certain information with respect to our net share of production attributable to our properties for the years ended December 31, as follows:

	2006	2005	2004
Production:			
Natural gas (Mcf)	12,005,600	11,372,000	10,000,100
Oil (Bbl)	401,440	395,550	432,400
Total (Mcfe)	14,414,240	13,745,300	12,594,600
Average price, net of hedges:			
Natural gas (Mcf)	$ 6.08	$ 6.36	$ 4.56
Oil (Bbl)	$ 48.80	$ 35.99	$ 26.24
Average production cost (per Mcfe):			
LOE	$ 1.19	$ 0.93	$ 0.97
Production and other taxes	0.67	0.77	0.57
Total	$ 1.86	$ 1.70	$ 1.54

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2006:

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	403	151	554	306.66	6.62	313.28
New Mexico	2	189	191	1.91	179.51	181.42
Colorado	—	81	81	—	61.36	61.36
Montana	3	171	174	0.47	34.70	35.17
Nebraska	—	29	29	—	29.00	29.00
Other states	8	99	107	1.58	20.34	21.92
Total	416	720	1,136	310.62	331.53	642.15

Acreage

The following table summarizes our undeveloped, developed and total acreage by state as of December 31, 2006 (in thousands):

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Wyoming	41,019	28,282	20,771	11,487	61,790	39,769
New Mexico	24,911	24,329	25,027	22,231	49,938	46,560
Colorado	42,990	33,949	39,378	33,648	82,368	67,597
Montana	692,434	137,571	83,877	15,334	776,311	152,905
Nebraska	18,092	18,079	47,432	45,444	65,524	63,523
Other states	28,588	12,990	53,878	10,650	82,466	23,640
Total	848,034	255,200	270,363	138,794	1,118,397	393,994

Competition. The oil and gas industry is highly competitive. We compete with a substantial number of companies ranging from those that have greater financial resources, personnel, facilities and in some cases, technical expertise to the multitude of smaller, aggressive new start-up companies. Many of these companies explore for, produce and market oil and natural gas. The primary areas in which we encounter considerable competition are in recruiting and maintaining high quality staff, locating and acquiring leasehold acreage for drilling and development activity, locating and acquiring producing oil and gas properties, locating and obtaining sufficient drilling rig and contractor services and securing purchasers and transportation for the oil and natural gas we produce.

Seasonality of Business. Weather conditions affect the demand for, and prices of, natural gas and can also temporarily reduce production and delay drilling activities, which in turn impacts our overall business plan. The demand for natural gas is typically higher in the fourth and first quarters of our fiscal year, resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations on a quarterly basis may not reflect results which may be realized on an annual basis.

Regulation. We are subject to federal, state, tribal and local environmental, health and safety laws and regulations. Crude oil and natural gas development and production activities are subject to various laws and regulations governing a wide variety of matters, including, among others, prevention of waste and pollution and protection of the environment. Environmental laws and regulations are frequently changed and subject to interpretation and tend to become more onerous over time. Many governmental bodies have issued rules and regulations that can be difficult and costly to comply with, and that carry substantial penalties for non-compliance. The Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time, but that now require remedial work to meet changing regulatory standards.

These regulations require permits to drill wells, bonding requirements to drill or operate wells, and regulations regarding the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. The effect of these regulations can limit the number of wells or the locations where we can drill.

We must comply with numerous and complex regulations governing activities on federal and state lands, notably the National Environmental Policy Act, the Endangered Species Act, the Resource Conservation and Recovery Act, the National Historic Preservation Act, the Clean Water Act and the Clean Air Act.

Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to gas and oil operations on tribal lands. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. Each Native American tribe is a sovereign nation possessing the power to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on tribal lands. One or more of these factors may increase the Company's costs of doing business on tribal lands and impact the viability of its gas, oil and transportation operations on such lands.

Environmental. Our operations are subject to various federal, state and local laws and regulations relating to the discharge of materials into, and the protection of the environment. We must account for the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures (such as spill prevention, control and countermeasure plans, storm water pollution prevention plans, state and federal air quality permits, and underground injection control disposal permits), and the remediation of petroleum-product contamination.

Under state and federal laws, we could also be required to remove or remediate previously disposed waste, including waste disposed of or released by us, or prior owners or operators, in accordance with current laws, or to otherwise suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. We generate waste that is already subject to the RCRA and comparable state statutes. The EPA and various state agencies limit the disposal options for those wastes. It is possible that certain oil and gas wastes exempt from treatment as RCRA wastes may in the future be designated as wastes under RCRA or other applicable statutes.

For additional information on our oil and natural gas operations, see Note 23 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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 MW as of December 31, 2006. We also hold minority interests in several power-related funds with a net ownership interest of 11 MW.

Portfolio Management. We maintain a geographically diverse portfolio of power plants in our wholesale energy group, with a focus on the western region of the United States. The fuel mix of our unregulated generation 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. Currently, we sell approximately 99 percent of our unregulated generating capacity under contracts having terms greater than one year. 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. The contracted purchasers of capacity and energy from our facilities are load-serving utility companies.

Rocky Mountain and West Coast Facilities. As of December 31, 2006, we had approximately 978 net MW of name plate generating capacity in the WECC states of Colorado, Nevada, Wyoming, California and Idaho, as follows:

Power Plant	Fuel Type	State	Total Capacity (MW)	Interest	Net Capacity (MW)	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 MW. The Fountain Valley and Valmont facilities operate in simple cycle. 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 MW, combined-cycle, gas-fired plant northeast of Las Vegas, Nevada, and is a QF under PURPA. We sell 45 MW of power from this plant to NPC under a long-term contract that expires in 2024. Under the terms of the NPC contract, we assume the fuel price risk associated with the energy generation. The project also sells steam production to Windset Greenhouses (Nevada), Inc., under a one-year agreement that contains annual renewal provisions and initially expires on July 31, 2007. Our Las Vegas II facility is a wholly-owned, 224 MW, combined-cycle, gas-fired plant that became operational early in 2003. The capacity and power from this plant is sold to NPC under a long-term tolling agreement, which expires December 31, 2013.

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 WRDC coal mine. The Gillette CT has a total capacity of 40 MW 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 temporarily 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 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 can 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 MW, which commenced operations in the first quarter of 2003. Prior to ownership of Cheyenne Light, we entered into agreements to sell 60 MW 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 MW of unit contingent capacity and energy to MEAN for a term of 10 years, expiring February 2013. As with the Gillette CT power purchase agreement, Cheyenne Light temporarily assigned the Wygen I power purchase agreement to PSCo for the term of its all-requirements power purchase agreement. After the PSCo contract expires on December 31, 2007, the output will then revert back to Cheyenne Light. 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 MW, "Cheng-cycle," gas-fired power plant in Ontario, California, which we currently operate as a baseload plant. Electrical output from the plant is sold under a 25-year power purchase agreement with SCE, which expires in May 2010. The project also sells steam production to Sunkist Growers, Inc. under a five-year agreement, which terminates in November 2007. In order to maintain QF status and the underlying power purchase agreement, the project must maintain a thermal energy host.

Harbor Cogeneration Facility. Harbor Cogeneration is a 98 MW, combined-cycle, gas-fired plant located at the Port of Long Beach, California. We sell all of the capacity and energy of the facility to SCE under a tolling agreement, which expires 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 schedule that ends on October 1, 2008. Termination payments are received on a quarterly basis and are expected to total $12.0 million in 2007 and $8.4 million in 2008.

Idaho Cogeneration Facilities. We own a 50 percent interest in two QF facilities in Rupert and Glenns Ferry, Idaho. Rupert and Glenns Ferry are both 11 MW, combined-cycle, gas-fired plants. Electrical output from the facilities is sold to Idaho Power Company under 20-year Energy Sales Agreements, which expires 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.

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 11 MW. We account for our investment in the funds under the equity method of accounting and as of December 31, 2006, we had a $5.5 million investment balance in the funds. The funds have been liquidating their investments in recent years. Accordingly, we expect our returns from these investment funds to diminish in the future.

Fund Name	Number of Plants	Total Capacity (MW)	Interest	Net Capacity (MW)
Energy Investors Fund II, L.P.	1	9.4	5.7%	0.5
Project Finance Fund III, L.P.	5	161.1	4.5%	7.2
Caribbean Basin Power Fund, Ltd.	3	76.5	4.3%	3.3
Total Fund Interests		247.0		11.0

Project Development Program. Through our project development program, we pursue the acquisition or development 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. To mitigate fuel price risk, we prefer long-term contracts that are tolling agreements where our counterparty provides the required fuel. We seek long-term contracts with either utilities serving native customer loads under state utility commission-approved contracts, or other investment-grade counterparties.

Competition. The independent power industry is replete with strong and capable competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than we possess.

The 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 and have begun allowing utilities to reinvest in power generation assets.

EPA 2005 repealed PUHCA and transferred oversight of holding companies to FERC effective February 8, 2006. On December 8, 2005, FERC issued final rules implementing the enactment of Public Utility Holding Company Act of 2005, which were effective February 8, 2006. We cannot predict the long-term effect of such regulation or how FERC will interpret the new rules. 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.

Regulation. We are subject to a broad range of federal, state and local energy and environmental laws and regulations which 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 operates in compliance with such requirements, including the following:

Energy Policy Act of 2005. EPA 2005 was signed into law on August 8, 2005. EPA 2005 repealed PUHCA 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.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for 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" 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. 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, Idaho and Ontario facilities as QFs. 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.

Environmental Regulation.

Air Quality. Our Gillette CT, Wygen I, Arapahoe, Valmont, Fountain Valley and Las Vegas II plants are all subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold 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 electric utility's 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 allowance requirements 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 cost of obtaining allowances needed for future projects into our overall financial analysis of such projects.

Title V of the federal Clean Air Act requires 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 have received permits.

In March 2005, the EPA issued mercury emission requirements for fossil-fuel-fired steam electric power plants. Wygen I will be subject to the monitoring, cap and trade requirements beginning in 2010. Testing at Wygen I was conducted during 2006, to gain understanding and knowledge of the mercury control and monitoring technology, which in turn will enable us to determine the best approach to managing compliance with Wyoming mercury emission caps. There are several pending legal actions involving other parties, challenging various aspects of the mercury rule. Until these legal efforts and emission control system evaluation efforts are finalized, we cannot fully evaluate the impact of mercury regulations on the operation of our facilities.

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. Ash and wastes from flue gas and sulfur removal from the Wygen I plant are deposited in mined areas at our WRDC coal mine. This disposal area is 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 would 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 can provide no assurance that pollution will not occur over time. In this event, we could experience material costs to mitigate any resulting damages.

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.

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 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 reopener 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. Additionally, the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations. All of our facilities regulated under this program have their required plans in place.

Coal Mining Segment

Our coal mining segment operates through our WRDC subsidiary. We mine and process low-sulfur, sub-bituminous coal at our coal mine near Gillette, Wyoming. The WRDC coal 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 2006. In a basin characterized by thick coal seams, our overburden ratio, a comparison of the amount of dirt removed to a ton of coal uncovered, has historically approximated a 1:1 ratio. In recent years this has trended towards a 2:1 ratio, where it is expected to remain for the next several years.

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, 2006, we had coal reserves of approximately 285 million tons, based on internal engineering studies. The reserve life is equal to approximately 55 years at expected production levels.

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

- our electric utility, Black Hills Power;
- the 362 MW Wyodak power plant owned 80 percent by PacifiCorp and 20 percent by Black Hills Power;
- PacifiCorp for 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 MW Wygen II plant, which is currently under construction and expected to achieve commercial operation by January 1, 2008. The plant is being constructed by Cheyenne Light at the Neil Simpson Complex near Gillette, Wyoming and is expected to utilize approximately 0.5 million tons of coal per year; 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, if constructed, would be expected to utilize approximately 0.5 millions 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 Power’s 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 SDPUC, the WPSC and the City of Gillette that coal for Black Hills Power’s operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant, which was 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 was executed in 2001 and terminates in 2022.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically our off-site sales have been to consumers within a close proximity to our mine. Due to the economic limitations on transporting our lower-heat content coal, we do not actively promote the sale of our coal in distant markets.

Environmental Regulation. The construction and operation of coal mines 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.

Mine Reclamation. Under federal and state laws and regulations, we must submit applications to, and receive approval from, the WDEQ for a mining and reclamation plan which provides for orderly mining, reclamation and restoration of our entire WRDC coal mine. 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 currently have approximately $16.0 million accrued on our accompanying Consolidated Balance Sheets for reclamation costs. Additional requirements in the future could be imposed that would cause an unexpected material or significant 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 WRDC coal mine. Because of the thick coal seam and relatively shallow overburden, the current restoration plan would leave these depressions having limited reclamation potential, with interior drainage only. Although the WDEQ has accepted the current plan to limit reclamation of these depressions, it 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 WDEQ could require us to conduct additional reclamation of the depressions, particularly if the WDEQ finds that the current limited reclamation and drainage results in exceedances in the WDEQ’s water quality standards.

Another situation that could result in unexpected increases in costs is the current State of Wyoming re-examination of ash disposal practices. The WRDC coal mine is currently allowed to dispose of ash below the future groundwater table, as state-approved studies have shown no future offsite impacts to groundwater due to this practice. If the state alters this approval at some point in the future, increased costs could be incurred due to loss of mine backfill and for specialized placement of ash at alternate approved sites within the mine.

Energy Marketing Segment

We market natural gas and crude oil in specific regions of the United States and Canada. Our marketing operations are headquartered in Golden, Colorado, with a satellite sales office in Calgary, Alberta, Canada. We engage in physical and financial wholesale energy marketing and offer storage and transportation services as well as price risk management products and services to a variety of customers. The customers of our energy marketing 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, 2006 were approximately 1.6 million MMBtu of gas, and for the period May 1, 2006 to December 31, 2006 were approximately 8,800 barrels of oil.

This segment previously included the Houston, Texas based operations of our subsidiary, BHER, which is now reported as discontinued operations. On March 1, 2006, we sold all of the operating assets to Sunoco Logistics Partners L.P. The sale included the crude oil marketing business, the 200-mile Millennium Pipeline system and the 190-mile Kilgore Pipeline system and related facilities.

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

Competition. The energy marketing industry is characterized by numerous large, strong and capable competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than we possess.

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 the marketing company and through our credit policy and procedures. These policies and procedures limit speculative positions and specify various maximum risk exposure levels within which the marketing company must operate. These policies are established and approved by our Executive Risk Committee and Executive Credit Committee and reviewed by our board of directors. These committees, which include senior executives, meet on a regular basis to review the Company’s risk and credit activities and to monitor compliance with the adopted policies. The policies are reviewed and monitored on a regular basis.

We further limit the exposure of our parent holding company, Black Hills Corporation, to energy marketing risks by maintaining a separate credit facility for our energy marketing company. This credit facility provides security interests limited to the assets of the marketing company. In addition, we limit the number and amount of any parent guarantees for energy marketing; as of December 31, 2006, we had no parent guarantees for our energy marketing company.

Other Properties

We own an eight-story, 47,000 square foot office building in Rapid City, South Dakota, where our corporate headquarters is located. 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 and lease an additional 12,180 square feet of office space. In Cheyenne, Wyoming, we own a business office with approximately 13,400 square feet, and a service center and garage with an aggregate of approximately 28,300 square feet. We lease an aggregate of 36,200 square feet of office space in Golden, Colorado.

Employees

At January 31, 2007, we had 819 full-time employees. We have experienced no labor stoppages or significant labor disputes in recent years. The following table sets forth the number of employees by business:

	Number of Employees
Corporate	162
Black Hills Power (1)	302
Cheyenne Light (2)	91
Wholesale Energy Group	264
Total	819

(1) Approximately 55 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, 2009.

(2) Approximately 71 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 with the SEC should be considered for a better understanding of our Company. These important factors and other matters discussed herein could cause our actual results or outcomes to differ materially from those discussed in the forward looking statements included elsewhere in this document.

Our utilities may not raise their retail rates without prior approval of the SDPUC, the WPSC and the MTPSC. If either utility seeks rate relief, it could experience delays, reduced or partial rate recovery, or disallowances in rate proceedings.

Because our utilities are generally unable to increase their base rates without prior approval from the SDPUC, the WPSC, and the MTPSC, our returns could be threatened by plant outages, machinery failure, increased purchased power costs, acts of nature, acts of terrorism or other unexpected events over which our utilities have no control that could cause operating costs to increase and operating margins to decline. While we have cost pass-through mechanisms in place that allow recovery of increased costs related to fuel, purchased power, transmission and natural gas, there is no guarantee that all increases in these costs will be recovered. Additionally, our utilities' general operating costs and investments are subject to the review of the SDPUC or the WPSC. These commissions could find certain costs or investments are not prudent and not recoverable in our rates, thus negatively affecting our revenues.

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 interpretation of available technical data and various assumptions, including assumptions relating to economic factors. Significant inaccuracies in interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of reserve estimates 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. These variances may be significant. Any significant variance from the assumptions used could cause the actual quantity of our reserves, and future net cash flow to be 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.

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

Execution of our future growth plan is dependent on successful completion of ongoing and future acquisition, development and expansion activities. We can provide no assurance that we will be able to complete acquisitions or development projects we undertake or continue to develop attractive opportunities for growth. Factors that could cause our activities to be unsuccessful include:

- our inability to obtain required governmental permits and approvals;
- our inability to obtain financing on acceptable terms, or at all;
- the possibility that one or more rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- capital market conditions;
- our inability to successfully integrate any businesses we acquire;
- our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- 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;
- changes in federal or state laws and regulations;
- fuel prices or fuel supply constraints;
- transmission constraints; and
- competition.

We can provide no assurance that 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 expected results include:

- delay in, and restrictions imposed as part of 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 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, with a negative outlook by Moody's, and BBB-, with a stable outlook by S&P. Any reduction in our ratings by Moody's or S&P would reduce our credit rating with that agency to non-investment grade status, which could adversely affect our ability to refinance or repay our existing debt or 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, our $86.8 million Black Hills Colorado project financing and our $24.2 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.

Construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve significant risks which could reduce revenues or increase expenses.

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

- the inability to obtain required governmental permits and approvals;
- contract restrictions upon the timing of scheduled outages;
- cost of supplying or securing replacement power;
- the unavailability of equipment and labor supply;
- 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 reduce revenues, increase expenses, or cause us to incur 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 timely or adequate to cover lost revenues, increased expenses or liquidated damage payments.

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

A substantial portion of our net income in recent years was attributable to sales of wholesale electricity and natural gas into a robust market. Energy 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, unpredictable price fluctuations over relatively short periods of time.

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

Our mining operation requires a reliable supply of replacement parts, explosives, fuel, tires and steel-related products. If the cost of any of these increase significantly, or if a source of these supplies or mining equipment was unavailable to meet our replacement demands, our profitability could be lower than our current expectations. In the past year, industry-wide demand growth has exceeded supply growth for certain surface mining equipment and off-the-road tires. As a result, lead times for some items have generally increased to several months.

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, tribal and local authorities. We generally must obtain and comply with a variety of licenses, permits and other approvals in order to operate. 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, which could 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, whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We strive to comply with all applicable environmental laws and regulations. Future steps to bring our facilities into compliance, if necessary, could be expensive, and could adversely affect our results of operation and financial condition. We expect our environmental expenditures to be substantial in the future due to the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate.

Our agreements with counterparties 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 occasionally serve as our counterparties. In addition, we have project level financing arrangements 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.

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. Significant inaccuracies in interpretation or modeling could materially affect the quantity and quality of our reserves. The accuracy of reserve estimates is a function of engineering and geological interpretation 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 require reserve revisions either upward or downward from prior reserve estimates.

Ongoing changes in the United States utility industry, including state and federal regulatory changes, a potential increase in the number or geographic scale 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 experiencing increasing competitive pressures as a result of:

- EPA 2005 and the repeal of PUHCA;
- industry consolidation;
- consumer demands;
- transmission constraints;
- renewable resource supply requirements;
- 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 led to the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. 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 price limitations and other mechanisms may adversely affect the profitability of 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.

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, so investments in our subsidiaries are our primary assets. Our operating cash flow and 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 applicable contractual or regulatory restrictions that 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. 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 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 have recently entered into a definitive agreement to acquire utility assets from Aquila. There are many risks associated with our ability to complete the transaction and subsequently achieve the anticipated benefits of our acquisition.

We may not be able to obtain the approvals required to complete the acquisition or, in order to do so, we may be required to comply with material restrictions or conditions.

Our acquisition of the utility assets is subject to various approvals from the FERC and various utility regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms of the acquisition, including restrictions or conditions on the business, operations, or financial performance of the gas utilities and electric utility that we would acquire from Aquila, following completion of the acquisition. These conditions or changes could impose additional costs on us or limit our revenues following the acquisition, or may impose unacceptable conditions on our operation of the gas utilities and electric utility assets, which could delay the completion of or cause us to abandon our acquisition.

If we do not complete the acquisition, we will still incur and remain liable for significant transaction costs, including legal, accounting, financial advisory, filing, printing and other related costs.

If completed, we may not be able to integrate the utility operations we acquire into our existing businesses and operations, or achieve the intended results.

We expect that the acquisition will result in various benefits. Achieving the anticipated benefits of our acquisition of those assets is subject to a number of uncertainties and we cannot assure you that the gas utilities and the electric utility businesses we would acquire from Aquila can be integrated in an efficient and effective manner, or that once integrated, they will prove to be profitable.

We will be subject to business uncertainties while the acquisition is pending that could adversely affect our financial results.

Uncertainty about the effect of the acquisition on employees and customers may have an adverse effect on us. Although we intend to take steps designed to eliminate or at least reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the acquisition is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the acquisition, as employees and prospective employees may experience uncertainty about their future roles with the addition of the gas utilities and electric utility we would acquire from Aquila. If despite our retention and recruitment efforts, key employees depart or fail to accept employment with us because of issues relating to uncertainty and difficulty of integration or a desire not to remain with us, our financial results could be affected.

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, our cost of capital and our other operating costs, which could adversely affect our ability to complete the acquisition.

Our issuer credit rating is Baa3, with a negative outlook by Moody's and BBB-, with a stable outlook by S&P. While we do not expect any negative effect on our credit rating from our proposed acquisition of the utility assets, we cannot assure you that our credit ratings will not be lowered as a result of the proposed acquisition or for any other reason, including the failure to consummate the acquisition of the utility assets. Any reduction in our ratings by Moody's or S&P would reduce our credit rating with that agency to non-investment grade status, and could adversely affect our ability to complete the Aquila transaction, to refinance or repay our existing debt and to complete new financings on acceptable terms or at all.

We can provide no assurance that we will be able to close our proposed new acquisition credit facility or any necessary backstop revolving credit facility. Inability to close on these facilities could adversely impact our ability to complete the Aquila transaction.

We have obtained a commitment letter with respect to a new $1.0 billion senior unsecured credit facility to, among other things, fund our acquisition of the utility assets. We have also obtained a commitment letter with respect to a $500.0 million, 364 day backstop revolving credit facility. Should we be unable to obtain sufficient lender consent to amend our existing revolving credit facility to allow for the proposed Aquila transaction, the backstop revolving credit facility would refinance our existing facility. Our ability to borrow amounts under our proposed new acquisition credit facility or a backstop revolving credit facility will be subject to the execution of customary documentation, including security documents, satisfaction of certain customary conditions precedent and compliance with terms and conditions included in the loan documents. Prior to each drawdown under either the acquisition facility or a backstop facility, we will be required, among other things, to meet specified financial ratios and other requirements. To the extent that we are not able to satisfy these requirements, we may not be able to draw down the full amount of the facilities, which could adversely impact our ability to complete the Aquila transaction.

Restrictive covenants in our proposed new acquisition credit facility will impose financial and other restrictions on us, including our ability to pay dividends.

Our proposed new acquisition facility will impose operating and financial restrictions on us and will require us to comply with certain financial covenants. These restrictions and covenants may limit our ability to, among other things:

- pay dividends if an event of default has occurred and is continuing under our proposed new acquisition facility or if the payment of the dividend would result in an event of default;
- incur additional indebtedness, including through the issuance of certain guarantees;
- create liens on our assets;
- merge or consolidate with, or transfer all or substantially all our assets to, another person; or
- change our business.

> Therefore, we may need to seek permission from the lenders under our acquisition facility in order to engage in some corporate actions. Our lenders' interests may be different from ours and we cannot guarantee that we will be able to obtain our lenders' consent when needed. If we do not comply with the restrictions and covenants in our proposed acquisition facility, we will not be able to pay dividends, finance our future operations, make acquisitions or pursue business opportunities.

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, were 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, both of which could adversely affect our earnings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the "Legal Proceedings" sub caption within Item 8, Note 18, "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 2006.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 44, 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 17 years of experience with us.

Thomas M. Ohlmacher, age 55, has been the President and Chief Operating Officer of our Wholesale Energy Group since November 2001. He served as Senior Vice President – Power Supply and Power Marketing from January 2001 to November 2001 and Vice President – Power Supply from 1994 to 2001. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher has 32 years of experience with us.

Linden R. Evans, age 44, 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. Mr. Evans has 5 years of experience with us.

Mark T. Thies, age 43, 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 9 years of experience with us.

Steven J. Helmers, age 50, 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. Mr. Helmers has 6 years of experience with us.

Maurice T. Klefeker, age 50, was appointed 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. Mr. Klefeker has 7 years of experience with us.

James M. Mattern, age 52, 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 19 years of experience with us.

Roxann R. Basham, age 45, was appointed 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 23 years of experience with us.

Kyle D. White, age 47, has been Vice President – Corporate Affairs since January 30, 2001 and Vice President – Marketing and Regulatory Affairs since July 1998. Mr. White has 24 years of experience with us.

Garner M. Anderson, age 44, was appointed Vice President, Treasurer and Chief Risk Officer in October 2006. He had served as Vice President and Treasurer since July 2003. Mr. Anderson has 18 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 18 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 February 1, 2007, we had 5,129 common shareholders of record and approximately 15,400 beneficial owners, representing all 50 states, the District of Columbia and 11 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 February 2007 meeting, our board of directors raised the quarterly dividend to $0.34 per share, equivalent to an annual dividend of $1.36 per share, marking the 37th consecutive annual dividend increase for the Company.

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, 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 interest expense 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. As of December 31, 2006, we are in compliance with all covenants and accordingly are not restricted from paying any currently declared dividends.

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, 2006

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.33	$ 0.33	$ 0.33	$ 0.33
Common stock prices				
High	$ 40.00	$ 37.52	$ 36.86	$ 37.95
Low	$ 32.92	$ 32.46	$ 33.20	$ 33.38

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

UNREGISTERED SECURITIES ISSUED DURING THE FOURTH QUARTER OF 2006

No unregistered securities were issued during the fourth quarter of 2006.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
October 1, 2006 - October 31, 2006	712(1)	$ 34.39	—	—
November 1, 2006 - November 30, 2006	—	$ —	—	—
December 1, 2006 - December 31, 2006	1,203(2)	$ 36.50	—	—
Total	1,915	$ 35.72	—	—

(1) Shares were acquired from certain officers and key employees under the share withholding provisions of the Restricted Stock Plan for payment of taxes associated with the vesting of restricted stock.

(2) Includes 283 shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan, and 920 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,	2006	2005	2004	2003	2002
Total Assets (in thousands)	$ 2,244,676	$ 2,120,258	$ 2,029,588	$ 2,044,555	$ 1,985,358
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 2,242,396	$ 1,928,559	$ 1,778,615	$ 1,698,411	$ 1,527,303
Accumulated depreciation and depletion	(596,029)	(518,525)	(465,845)	(395,518)	(348,097)
Capital Expenditures (in thousands)	$ 308,450	$ 208,856	$ 90,974	$ 116,691	$ 303,191
Capitalization (in thousands)					
Long-term debt, net of current maturities	$ 628,340	$ 670,193	$ 733,581	$ 868,459	$ 540,958
Preferred stock equity	—	—	7,167	8,143	5,549
Common stock equity	790,041	738,879	728,598	701,604	529,614
Total capitalization	$ 1,418,381	$ 1,409,072	$ 1,469,346	$ 1,578,206	$ 1,076,121
Capitalization Ratios					
Long-term debt, net of current maturities	44.3%	47.6%	49.9%	55.0%	50.3%
Preferred stock equity	—	—	0.5	0.5	0.5
Common stock equity	55.7	52.4	49.6	44.5	49.2
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues (in thousands)	$ 656,882	$ 613,541	$ 445,543	$ 559,315[1]	$ 348,784
Net Income Available for Common (in thousands):					
Retail services	$ 24,188	$ 20,119	$ 19,209	$ 23,999	$ 30,138
Wholesale energy	55,372	26,164[2]	40,862	42,961[2]	35,445
Corporate expenses and intersegment eliminations	(5,514)	(13,491)	(3,790)	(7,970)	(3,342)
Income from Continuing Operations Before Changes in Accounting Principles	74,046	32,792	56,281	58,990	62,241
Discontinued operations	6,973	628	1,692	7,427	(1,685)
Changes in accounting principles, net of tax	—	—	—	(5,195)	896
Preferred dividends	—	(159)	(321)	(258)	(223)
	$ 81,019	$ 33,261	$ 57,652	$ 60,964	$ 61,229
Dividends Paid on Common Stock (in thousands)	$ 43,960	$ 42,053	$ 40,210	$ 37,025	$ 31,116
Common Stock Data (in thousands)					
Shares outstanding, average	33,179	32,765	32,387	30,496	26,803
Shares outstanding, average diluted	33,549	33,288	32,912	31,015	27,167
Shares outstanding, end of year	33,369	33,156	32,478	32,298	26,933
Earnings Per Share of Common Stock (in dollars)[3]					
Basic earnings (losses) per average share -					
Continuing operations	$ 2.23	$ 1.00	$ 1.73	$ 1.93	$ 2.31
Discontinued operations	0.21	0.02	0.05	0.24	(0.06)
Change in accounting principle	—	—	—	(0.17)	0.03
Total	$ 2.44	$ 1.02	$ 1.78	$ 2.00	$ 2.28
Diluted earnings (losses) per average share -					
Continuing operations	$ 2.21	$ 0.98	$ 1.71	$ 1.90	$ 2.29
Discontinued operations	0.21	0.02	0.05	0.24	(0.06)
Changes in accounting principles	—	—	—	(0.17)	0.03
Total	$ 2.42	$ 1.00	$ 1.76	$ 1.97	$ 2.26
Dividends Paid per Share	$ 1.32	$ 1.28	$ 1.24	$ 1.20	$ 1.16
Book Value Per Share, End of Year	$ 23.68	$ 22.28	$ 22.43	$ 21.72	$ 19.66
Return on Average Common Stock Equity (year-end)	10.6%	4.5%	8.1%	9.9%	11.8%

Operating Statistics:

Years ended December 31,	2006	2005	2004	2003	2002
Generating capacity (MW):					
Utility (owned generation)	435	435	435	435	435
Utility (purchased capacity)	50	50	50	55	60
Independent power generation(4)	989	1,000	1,004	1,002	950(5)
Total generating capacity	1,474	1,485	1,489	1,492	1,445
Electric utility sales (MW-hours):					
Retail electric sales	1,632,352	1,582,841	1,509,635	1,536,836	1,515,635
Contracted wholesale sales	647,444	619,369	614,700	614,888	757,051
Wholesale off-system	942,045	869,161	926,461	773,801	673,051
Total utility electric sales	3,221,841	3,071,371	3,050,796	2,925,525	2,945,737
Electric and gas utility sales:					
Electric MW-hours	919,938	889,210	—	—	—
Gas sales Dth	4,387,767	4,062,590	—	—	—
Oil and gas production sold (MMcfe)	14,414	13,745	12,595	10,843	7,398
Oil and gas reserves (MMcfe)	199,092	169,583	173,417	156,396	57,793
Tons of coal sold (thousands of tons)	4,717	4,702	4,780	4,812	4,052
Coal reserves (thousands of tons)	285,000	290,000	294,000	263,000	273,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,598,200	1,427,400	1,226,600	897,850	683,500
Crude oil physical sales (Bbls) (6)	8,800	—	—	—	—

Certain items related to 2002 through 2005 have been restated from prior year presentations to reflect the classification of the oil marketing and transportation business as discontinued operations in 2006 (see Notes 1 and 16 of Item 8. Financial Statements and Supplementary Data).

(1) Includes $114.0 million of contract termination revenue.
(2) 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.
(3) In May 2003 we issued 4.6 million common stock shares, which dilute our earnings per share in subsequent periods.
(4) Includes 40 MW in 2004 and 2003, respectively and 82 MW in 2002**,** which have been reported as "Discontinued operations."
(5) Includes the 224 MW expansion at the Las Vegas cogeneration power plant that was placed in service on January 3, 2003.
(6) Represents crude marketing activities in the Rocky Mountain region, which began May 1, 2006

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 20 TO THE NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS IN THIS ANNUAL REPORT ON FORM 10-K.

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 an integrated 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	Oil and gas
	Power generation
	Coal mining
	Energy marketing

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. Black Hills Power generates, transmits and distributes electricity to approximately 64,200 customers in South Dakota, Wyoming and Montana. Cheyenne Light serves approximately 38,900 electric customers and 32,600 natural gas customers in Cheyenne, Wyoming and vicinity. Our wholesale energy group, which operates through Black Hills Energy and its subsidiaries, engages in the production of natural gas, crude oil and coal primarily in the Rocky Mountain region; 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; and the marketing of natural gas and crude oil.

Industry Overview

The U.S. energy industry experienced another year of strong economic performance in 2006. Energy commodity prices continued to be high and volatile. Domestic energy prices continue to be influenced by global factors, including foreign economic growth, especially in China and Asia, domestic economic growth, the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions. Mild weather dominated the U.S. during the summer of 2006 and through early winter, reducing demand for fuel used for power generation and heating. At year-end 2006, domestic supplies of natural gas in storage were well above historical averages.

Progress in the energy industry in 2006 included the discovery of substantial oil and gas reserves in the Gulf of Mexico, increased exploration and production of oil and natural gas in the lower 48 states, continued planning and construction of liquefied natural gas port facilities, the proposal of additional coal-fired and nuclear power plants, the advancement of renewable energy resources and utilization. The industry has also experienced better cooperation between regulators and energy providers in many states seeking cooperative, constructive solutions to ongoing issues and rate cases.

The energy industry continues to adjust to change, including the trends of consolidation in the electric and gas utility sectors, increased private equity investment, and asset divestitures to narrow business strategies. The energy market place is still adjusting to the repeal of PUHCA, effective in early 2006; increased oversight of the FERC and increased environmental and emissions reviews and mandates. In recent years, several state regulatory agencies allowed electric utilities to construct and operate power plants in vertically integrated structures after years of discouraging or prohibiting such activity. As a result, the independent and merchant power industry was challenged in its ability to increase its market presence.

In the past year, the corporate structure of many energy companies underwent evaluation and change, largely from efforts to create additional shareholder value. Some companies are contemplating or implementing a realignment of assets, reflecting shifts in longer-term business strategies. Others are divesting certain energy properties to focus on core businesses, such as exiting unregulated power production or oil and gas production in favor of utility operations. Others continue to engage in mergers and acquisitions in a quest to improve economies of scale and returns to investors.

Many industry analysts expect an increase in capital investments across a wide spectrum of energy companies. A number of electric and gas utilities need to replace aging plants and equipment, and regulators are providing favorable recognition in rates for additional investment. Oil and gas producers are expected to continue to increase capital spending in response to relatively high prices. In response to relatively high seasonal supplies of natural gas and widening regional price differentials capital spending in certain producing areas may moderate or even be curtailed.

In 2006, the domestic coal industry benefited from a stronger price environment, in large part due to high and volatile natural gas prices. Coal prices have moderated recently in response to a trend of lower overall natural gas prices, compared to a year ago. Some deliveries of Powder River Basin coal in Wyoming were hampered by transportation disruptions, causing temporary difficulties for utilities in the West and Midwest. Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including U.S. allies, advocate reductions in carbon dioxide emission. Many states now encourage the industry to invest in renewable energy resources, such as wind power or the use of bio-mass as a fuel. In some instances, renewable energy use is mandated by state regulators. In the case of California, a new adopted interim standard requires that future imports of power must come from power plants with lower emission levels than currently associated with conventional coal-fired plants. Such restrictions could alter transmission flow of power in western states, as a large percentage of current power generation in the western grid comes from coal sources. Despite these longer-term challenges, the power generation industry continues to make improvements in emissions control in response to regulatory mandates. Emissions from new coal-fired plants are a fraction of those produced by power plants built a generation ago. As a result, coal remains an important, domestically available, and economical national energy resource that is vital to meet growing energy demand.

Energy providers, government authorities and private interests continue to address longer term issues concerning electric transmission, power generation capacity, the use of renewable and other diversified sources of energy, oil and natural gas pipelines and storage, and other infrastructure-related matters. Despite public and private efforts to promote conservation, the demand for energy is expected to increase steadily over time.

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of retail utility assets, including electric and gas distribution systems, fuel assets and electric generation assets. To optimize the value of our assets, we utilize our energy marketing and transportation expertise. Our focus on customers, whether retail utility customers, wholesale generation or marketing customers, provides opportunities to expand our businesses. Our balanced, integrated approach to retail utility operations, fuel production, power generation and energy marketing is supported by disciplined risk management practices. The diversity of our operations reduces reliance on any single business to achieve our strategic objectives. Our diversity is expected to provide a measure of stability to our business and financial performance during volatile or cyclical periods. It helps us reduce our total corporate risk, and allows 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 long-term strategy is to continue expanding our core retail utility, fuel asset and generation businesses, supplemented by our energy marketing operations. We will do this primarily by focusing on providing superior economic and performance value to customers, and by increasing our customer base. In the retail area, we seek to grow our existing utility asset base through construction of new rate-based generation facilities, and by adding new customers through the acquisition of additional retail utility properties, while maintaining our high customer service and reliability standards. In the fuel production area, we will continue to develop our existing inventory of oil and gas reserves while striving to maintain our positive relationships with mineral owners and regulatory authorities and working to develop additional markets for our coal production, including the development of additional power plants at our mine site. Our power generation business will focus on long-term contractual relationships with key wholesale customers, as well as new customers that will allow us to expand existing generation sites, or to construct or acquire new generation facilities. The expertise of our energy marketing business will continue to enable us to optimize the value of our asset-based businesses.

The following are key elements of our business strategy:

- operate our lines of business as retail and wholesale energy components. The retail utility component consists of electric and natural gas products and services. The wholesale component consists of fuel production, mid-stream assets, power production facilities and energy marketing;

- expand retail operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages;

- invest in, construct and expand our rate-base generation to serve our electric utilities;

- complete our proposed acquisition of certain Aquila-owned utility assets and successfully integrate and profitably operate our expanded utility operations;

- grow our reserves and increase our production of natural gas and crude oil;

- grow our energy marketing operations primarily through the expansion of producer and end-use origination services and, as warranted by the market, natural gas and crude oil storage and transportation opportunities;

- selectively 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";

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

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

- diligently manage the risks inherent in energy marketing;

- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;

- sell a large percentage of our capacity and energy production from our 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; and

- build and maintain strong relationships with wholesale power customers.

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, mid-stream assets, power production facilities and energy marketing. We achieve operating efficiencies through our retail and wholesale business groups. 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, generation and marketing segments integrate balanced, yet diverse strategic operations.

Expand retail operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For more than 65 years, we have provided strong retail utility services, based on delivering quality and value to our customers. Our tradition of accomplishment is expected to support efforts to expand our retail operations in other markets, most likely in the Midwest, West and in regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service and relationship-based approach to regulatory matters. The January 2005 acquisition of Cheyenne Light and the February 2007 announcement of the proposed acquisition of certain electric and gas utility assets of Aquila are examples of such expansion efforts. Retail operations also enhance other important business development, including gas transmission pipelines and storage infrastructure, which could promote other wholesale operations. Regulated retail utility operations can contribute substantially to the stability of our long-term cash flows, earnings and dividend policy.

Invest in, construct and expand our 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 are investing in and operating efficient power generation resources to transmit and distribute electricity to our customers. We provide power at reasonable and stable rates to our customers and earn solid returns for 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 safeguard the public interest. Second, regulators 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 our cost of capital.

We continue to advance our strategy as evidenced by the construction of Wygen II and the development and permitting of Wygen III. Construction of the 90 MW, coal-fired Wygen II plant is currently on schedule. Cost of the plant is currently expected to be approximately $182 million, including interim financing costs during construction. We expect to file a rate case in the first quarter of 2007 to recover the cost of Wygen II. In early 2007, we received a regulatory issued air permit for the Wygen III power plant. This enables us to move forward with other regulatory processes with the goal of commencing construction in late 2007 or early 2008.

Complete our proposed acquisition of certain Aquila-owned utility assets and successfully integrate and profitably operate our expanded utility operations. Our recently announced definitive agreement to acquire Aquila's utility properties in five states will significantly increase our regional presence and the size and scope of our utility operations. We believe that the expanded utility operations will enhance our ability to serve customers and communities and build value for our shareholders. In addition to other customary conditions, the completion of the transaction requires us to obtain state and federal regulatory approvals, and pass federal antitrust review. We will also need to access the capital markets to secure capital sufficient to fund our acquisition. This could be impacted by our ability to maintain our investment grade issuer credit rating. We expect that the acquisition will result in multiple benefits. We will strive to integrate our current and acquired utility operations to achieve these anticipated benefits.

Grow our reserves and increase production of natural gas and crude oil. Our strategy is to increase both reserves and production through a combination of drilling and acquisitions. Primary emphasis will be placed on developing our existing core properties located in the San Juan, Piceance and Powder River Basins. Specifically, we plan to:

- substantially increase our natural gas reserves primarily by focusing our operations on lower-risk development and exploration drilling on our existing properties;

- maintain working interests with other similar scale operators to provide exposure to additional producing basins;

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

- add natural gas reserves and increase production by focusing primarily on various 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; and

- support the future capital requirements of our drilling program by stabilizing cash flows with a hedging program that mitigates commodity price risk for a substantial portion of our established production for up to 2 years in the future.

Grow our energy marketing operations primarily through the expansion of producer and end-use origination services and, as warranted by the market, natural gas and crude oil storage and transportation opportunities. 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 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. 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. We have also added oil marketing within the Rocky Mountain region to our business portfolio and in the future may seek to construct and/or acquire mid-stream assets, such as regional pipelines, to facilitate and augment our marketing services.

Selectively 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. 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. Our emphasis is on small-scale buildouts to serve incremental growth and improve likelihood of permitting and siting.

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

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

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

Increase earnings 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 WRDC coal mine location. Our objective is to develop coal production operations to serve our mine-mouth coal-fired generation plants directly. We also plan to pursue future sales of coal to additional regional rail-served and truck-served customers.

Exploit our fuel cost advantages and our operating and marketing expertise to produce and sell power at attractive margins. We expect to selectively 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.

Diligently manage the risks inherent in energy marketing. 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. We have oversight committees that monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining credit facilities separate from our corporate facility.

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 establish counterparty credit limits and employ continuous credit monitoring with regular review of compliance under our credit policy by our executive credit committee that reports to our board of directors.

Sell a large percentage of our capacity and energy production from our 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, utility commission-approved contracts primarily to load serving utilities.

The first of our long-term power contracts expires in 2010, and nearly all expire before 2014. Such arrangements are presently under evaluation for renewal or extension, with or without potential revisions to the basic terms of the existing agreements. Most of the existing contracts have been reviewed by state regulatory agencies. Our power plants, particularly in Wyoming, the front range of Colorado, Las Vegas, Nevada and Long Beach, California are sited in regions of moderate to rapid population and load growth, and in advantageous locations with convenient access to both fuel supply and power transmission. In anticipation of renewal or extension, a contract review process generally begins about two years in advance of expiration, and we would expect to proceed with preliminary planning accordingly.

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 more volatile spot markets.

Prospective Information

We expect long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires continual capital deployment. 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.

<u>Retail Services Group</u>

Electric Utility

Business at our electric utility, Black Hills Power, remained strong in 2006. 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 we conducted 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 regulatory requirements, native load growth, plant availability and electricity demand and commodity prices in not only our service territory, but in the surrounding power markets as well.

On June 30, 2006, Black Hills Power filed an application with the SDPUC for an electric rate increase to be effective January 1, 2007. On December 28, 2006, the SDPUC approved a rate increase of 7.8 percent along with the addition of tariff provisions which provide for the automatic adjustment of rates, effective January 1, 2007. The cost adjustments would require the electric utility to absorb a portion of power cost increases, depending in part on earnings from certain short-term wholesale sales of electricity. Absent certain conditions, the order also restricts Black Hills Power from requesting an increase in base rates that would go into effect prior to January 1, 2010. The previous rate structure, in place since 1995, did not contain fuel or purchased power adjustment clauses and only provided the ability to request rate relief from energy costs in certain defined situations. South Dakota retail customers account for approximately 91 percent of the electric utility's total retail revenues.

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. We are on schedule with construction of Wygen II, a 90-MW baseload coal-fired power plant. The plant will be a regulated asset of Cheyenne Light. The facility is currently expected to cost approximately $182 million, including interim financing costs during construction. This power plant is expected to be in commercial operation by the end of 2007 and will require a rate review with the WPSC in order to recover capital and provide a return on invested capital. Presently, power is provided by PSCo under an all-requirements contract, which expires December 31, 2007. In addition, Cheyenne Light entered into a 20-year contract to purchase supplemental power of up to 30 MW of renewable wind power, beginning in 2008, pending regulatory and other approvals. We expect system demand in the Cheyenne, Wyoming vicinity over the next 10 years to increase at an annual compound rate of approximately two percent.

Pending Acquisition

On February 7, 2007, we announced an agreement with Aquila to purchase utility assets. If completed, the acquisition will dramatically increase the size and scope of our Retail services group. Through the transaction, we will acquire Aquila's one regulated electric utility in Colorado and their regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The transaction would add approximately 616,000 new utility customers (93,000 electric customers and 523,000 gas customers) to our current customer base.

<u>Wholesale Energy Group</u>

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. Our long-term compounded annual production growth target is 10 percent. Near term growth will come from development of our 2006 acquisitions in the Piceance Basin and the ongoing development of the San Juan and Piceance Basins.

We expect to deploy approximately $72.0 million of capital in 2007 developing our current properties. We will continue our focus on optimal deployment of capital as drilling and completion costs are expected to continue to rise due to persistent shortages in the industry. Our drilling program is focused on both proved reserves and the further delineation of existing fields, including development of additional locations in the San Juan Basin resulting from an approved increased density order received on January 30, 2007. We are also encouraged by recent approvals on our non-operated properties in Montana and Oklahoma. These approvals provide high confidence drilling opportunities in areas of well developed gathering infrastructure.

Energy Marketing

We expect lower earnings from this segment in 2007, as 2006 earnings were strong due to advantageous market conditions. Continued market volatility will enable us to extract economic value as we look to expand our business. We will continue to focus on producer, end-use origination, and gas storage and transportation services and a regional wholesale marketing strategy. This will be done while maintaining our conservative credit management and lower-risk profile that emphasizes short-term physical transactions.

Power Generation

We expect higher earnings from our Power Generation segment in 2007 primarily as a result of satisfactorily resolving maintenance issues in 2006 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 restored this plant's capacity and energy availability as of July 2006. At the Las Vegas I power plant, an extensive maintenance program initiated in the fourth quarter of 2005 was completed in April 2006. There were no major maintenance issues in the last six months of 2006 and contracted fleet plant availability was 97.9 percent during this period.

Coal Mining

Production from the coal mining segment is expected to primarily serve mine-mouth plant generation and select regional customers with long-term fuel needs. Assuming no significant coal-fired plant outages, we expect increased earnings from higher production rates, even though operating costs will increase due to higher equipment and labor costs, resulting from higher overburden ratios and increased production. Increased demand will come from additional mine-mouth generation either currently being constructed or in the permitting stages of development. A contract to provide coal to the Dave Johnston power plant expires in 2007. We currently have a put option to sell additional coal to the plant through 2009 and have begun to negotiate a possible contract renewal.

Recent Corporate Events

On February 22, 2007, we completed the sale of approximately 4.17 million shares of common stock at a price of $36.00 per share, to certain institutional investors through a private placement offering. The Company used the proceeds, net of issuance costs, for debt reduction.

Results of Operations

Consolidated Results

Results for the year 2006 reflect solid utility performance, strong energy marketing results and improved power generation performance. Results for the year also reflect the impacts of scheduled and unscheduled plant outages and lower natural gas prices.

Earnings for Black Hills Power increased 4 percent over the prior year. Plant availability for Black Hills Power was 97.1 percent, despite scheduled and unscheduled plant outages at the Wyodak plant. Cheyenne Light results reflect a rate increase, effective January 1, 2006, and a full year of operations. Construction of the 90 MW coal-fired Wygen II plant is on schedule and expected to be in commercial service by January 1, 2008.

Strong earnings from energy marketing are attributable to a $24.3 million increase in realized marketing margins, partially offset by a $10.8 million loss in unrealized mark-to-market losses. Daily average physical gas volumes marketed increased 12 percent over 2005. This segment also commenced oil marketing operations in the Rocky Mountain region beginning in May 2006.

Power generation improved earnings for 2006 as the Las Vegas plants were returned to normal operations after extensive repairs and maintenance for scheduled and unscheduled outages. This segment had contracted fleet power plant availability of over 93 percent for the year, despite the plant outages.

The earnings decline for the oil and gas segment is primarily due to lower average prices received for gas and increased LOE and depletion costs. Production was 14.4 Bcfe for the year, a 5 percent increase over 2005. Fourth quarter 2006 production, on a Bcfe basis, increased 15 percent over the fourth quarter of 2005 reflecting our successful drilling efforts, primarily in the San Juan Basin. This increased production trend is expected to continue with production from the San Juan Basin augmented by increased production from the Piceance Basin, which was acquired in 2006. Year-end oil and gas reserves were lower than expected as price and technical performance issues affected the year-end calculation.

Coal mining earnings decreased due to increased overburden expense resulting from a change in accounting, and higher mineral taxes, partially offset by increased revenues resulting primarily from a higher average price received.

Overview

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

	2006	2005	2004
Revenue:			
Retail services	$ 323,003	$ 297,681	$ 172,774
Wholesale energy	333,833	315,089	272,008
Corporate	46	771	761
	$ 656,882	$ 613,541	$ 445,543

	2006	2005	2004
Income (loss) from continuing operations:			
Retail services	$ 24,188	$ 20,119	$ 19,205
Wholesale energy	55,372	26,164	40,862
Corporate	(5,514)	(13,491)	(3,786)
	$ 74,046	$ 32,792	$ 56,281

The Corporate group represents unallocated costs for administrative activities that support the business segments. Corporate also includes business development activities that do not fall under the two business groups.

On January 21, 2005, we completed the acquisition of Cheyenne Light, an electric and natural gas utility serving customers in Cheyenne, Wyoming and vicinity. The results of operations of Cheyenne Light have been included in the accompanying Condensed Consolidated Financial Statements from the date of acquisition.

Discontinued operations in 2006 represents the operations and gain on sale of our crude oil marketing and transportation business, sold in March 2006. In addition to crude oil marketing and transportation operations, the 2005 and 2004 discontinued operations also include our Communications segment, Black Hills FiberSystems, Inc., which was sold in June 2005; and our 40 MW Pepperell power plant, which was sold in April 2005. Results of operations for 2005 and 2004 have been restated to reflect the operations discontinued.

Prior to the reclassification of the financial results of our Houston-based crude oil marketing and transportation business, BHER, into discontinued operations, the related revenues and cost of sales were presented on a gross basis. Accordingly, our operating revenues and expenses, as previously presented in the 2005 interim financial statements, are adjusted by the following to reflect crude oil marketing and transportation revenues and cost of sales in discontinued operations (in millions):

	Total 2006*	Total 2005	Total 2004
Operating revenues	$ 171.9	$ 778.1	$ 636.6
Cost of sales	$ 170.7	$ 765.2	$ 620.3

*Completed asset sale on March 1, 2006.

2006 Compared to 2005

Consolidated income from continuing operations for 2006 was $74.0 million, compared to $32.8 million in 2005, or $2.21 per share in 2006, compared to $0.98 per share in 2005. Income from discontinued operations, including the $8.9 million gain on the sale of the operating assets of the Energy marketing and transportation business, was $7.0 million or $0.21 per share in 2006, compared to income of $0.6 million or $0.02 per share in 2005. Return on average common stock equity in 2006 and 2005 was 10.6 percent and 4.5 percent, respectively.

The Retail Services Group's income from continuing operations increased $4.1 million in 2006 compared to 2005. Earnings from continuing operations from the electric utility increased $0.7 million and earnings from continuing operations from the electric and gas utility, acquired January 21, 2005, increased $3.4 million.

The Wholesale Energy Group's income from continuing operations increased $29.2 million in 2006 compared to 2005. Increased earnings from power generation of $32.4 million and from energy marketing of $3.5 million were offset by decreased earnings of $5.2 million at our oil and gas operations and $1.1 million from coal mining operations.

Unallocated corporate costs for the year ended December 31, 2006 decreased $8.0 million after-tax, compared to 2005. The decrease is primarily due to increased allocations of corporate costs and interest expense down to the subsidiary level and the 2005 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.

Consolidated operating expenses for 2006 decreased $27.5 million compared to 2005. Decreased operating expenses reflect the $52.2 million impairment charge at our power generation segment in 2005 offset by a $13.7 million increase in fuel and purchased power, a $6.0 million increase in depreciation expense and a $3.0 million increase in operations and maintenance. Higher fuel and purchased power costs were primarily the result of the increased cost of sales of electricity and gas at Cheyenne Light, which was acquired during 2005, partially offset by lower purchased power costs at Black Hills Power. The increase in depreciation expense is primarily due to higher depletion at the oil and gas segment. Increased operations and maintenance expense is primarily related to scheduled and unscheduled plant outages, partially offset by the receipt of $3.9 million of insurance proceeds for repairs on the Las Vegas II plant.

2005 Compared to 2004

Consolidated income from continuing operations for 2005 was $32.8 million, compared to $56.3 million in 2004, or $0.98 per share in 2005, compared to $1.71 per share in 2004. Income from discontinued operations was $0.6 million or $0.02 per share in 2005, compared to income of $1.7 million or $0.05 per share in 2004. Return on average common stock equity in 2005 and 2004 was 4.5 percent and 8.1 percent, respectively.

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.

The Wholesale Energy Group's income from continuing operations decreased $14.7 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 $8.2 million from energy marketing operations.

Corporate costs for the year ended December 31, 2005 increased $9.7 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 $214.8 million compared to 2004. Increased operating expenses reflect a $106.8 million increase in fuel and purchased power, a $52.2 million impairment charge at our power generation segment and a $33.4 million increase in Administrative and general costs. Higher fuel and purchased power costs were primarily the result of the increased 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.

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, 2005 and 2004 information has been revised to remove information related to operations that were discontinued.

Retail Services Group

Electric Utility

	2006	2005	2004
		(in thousands)	
Revenue	$ 193,166	$ 189,005	$ 173,745
Operating expenses	153,164	152,961	129,936
Operating income	$ 40,002	$ 36,044	$ 43,809
Income from continuing operations and net income	$ 18,724	$ 18,005	$ 19,209

The following tables provide certain electric utility operating statistics:

Electric Revenue
(in thousands)

Customer Base	2006	Percentage Change	2005	Percentage Change	2004
Commercial	$ 49,756	1%	$ 49,185	5%	$ 46,791
Residential	40,491	3	39,348	8	36,536
Industrial	20,694	4	19,982	1	19,796
Municipal sales	2,401	6	2,268	3	2,200
Contract wholesale	24,705	6	23,384	3	22,720
Wholesale off-system	42,489	(11)	47,647	25	38,228
Total electric sales	180,536	(1)	181,814	9	166,271
Other revenue	12,630	76	7,191	(4)	7,474
Total revenue	$ 193,166	2%	$ 189,005	9%	$ 173,745

Megawatt-Hours Sold

Customer Base	2006	Percentage Change	2005	Percentage Change	2004
Commercial	667,220	2%	655,076	4%	627,326
Residential	499,152	4	480,053	7	447,166
Industrial	433,019	4	417,628	3	406,209
Municipal sales	32,961	10	30,084	4	28,934
Contract wholesale	647,444	5	619,369	1	614,700
Wholesale off-system	942,045	8	869,161	(6)	926,461
Total electric sales	3,221,841	5%	3,071,371	1%	3,050,796

We established a new summer peak load of 415 MW in July 2006 and a new winter peak load of 356 MW in December 2005. We own 435 MW of electric utility generating capacity and purchase an additional 50 MW under a long-term agreement expiring in 2023.

	2006	2005	2004
Regulated power plant fleet availability:			
Coal-fired plants	95.5%	93.3%	93.3%
Other plants	98.7%	99.3%	98.5%
Total availability	97.1%	96.3%	95.9%

Resources	2006	Percentage Change	2005	Percentage Change	2004
MW-hours generated:					
Coal	1,729,636	0%	1,728,823	(1)%	1,753,693
Gas	54,299	46	37,239	34	27,825
	1,783,935	1	1,766,062	(1)	1,781,518
MW-hours purchased	1,553,024	11	1,399,212	3	1,361,409
Total resources	3,336,959	5%	3,165,274	1%	3,142,927

	2006	2005	2004
Heating and cooling degree days:			
Actual			
Heating degree days	6,472	6,488	6,553
Cooling degree days	931	830	522
Variance from normal			
Heating degree days	(10)%	(10)%	(9)%
Cooling degree days	56%	39%	(13)%

2006 Compared to 2005

Electric utility revenues increased 2 percent for the year ended December 31, 2006 compared to the same period in the prior year. Firm residential, industrial and contract wholesale sales increased 3 percent, 4 percent and 6 percent, respectively. For the year ended December 31, 2006, cooling degree days were 56 percent higher than normal and heating degree days were 10 percent lower than normal. Wholesale off-system sales decreased 11 percent due to an 18 percent decrease in average price received partially offset by an 8 percent increase in MW-hours sold.

Electric operating expenses were flat for the year ended December 31, 2006, compared to the prior year. Increases in fuel costs were primarily due to a 7 percent increase in average cost of steam generation and increased gas generation utilized for firm load demand and peaking needs due to scheduled and unscheduled outages at the Wyodak plant and warmer weather. Purchased power decreased primarily due to a 12 percent lower average cost per MW-hour offset by an 11 percent increase in MW-hours purchased. Operating expenses were also affected by increased repairs and maintenance costs for the Wyodak plant, incentive compensation costs and corporate allocations, partially offset by a decrease in power marketing legal costs relative to costs incurred in 2005 (See Note 18, "Commitments and Contingencies" to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for discussion of the power marketing legal settlement).

Income from continuing operations increased 4 percent primarily due to increased revenues and lower interest expense, offset by a 2005 deferred tax benefit adjustment of $1.9 million.

Rate Increase Settlement. During 2006 our electric utility filed an application with the SDPUC for an electric rate increase to be effective January 1, 2007. On December 28, 2006, we received an order from the SDPUC for a 7.8 percent increase in retail rates and approving the addition of tariff provisions for automatic adjustments. The cost adjustments will require the electric utility to absorb a portion of power cost increases partially depending on earnings on certain short-term wholesale sales of electricity. Absent certain conditions, the order also restricts Black Hills Power from requesting an increase in base rates that would go into effect prior to January 1, 2010. Our previous rate structure, in place since 1995, did not contain fuel or purchased power adjustment clauses and only provided the ability to request rate relief from energy costs in certain defined situations. South Dakota retail customers account for approximately 91 percent of the electric utility's total retail revenues.

The cost adjustments will require the electric utility to absorb a portion of purchased power and natural gas cost increases, partially depending on earnings from certain short-term wholesale sales of electricity.

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 MW-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 purchased power costs to cover the outage of Neil Simpson II, as well as a 31 percent increase in average price per MW-hour, and a 3 percent increase in MW-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 MW-hours generated. MW-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.

Electric and Gas Utility

	2006	January 21, 2005 to December 31, 2005
	(in thousands)	
Revenue	$ 132,189	$ 110,875
Purchased gas and electricity	104,922	89,642
Gross margin	27,267	21,233
Operating expenses	21,313	18,180
Operating income	$ 5,954	$ 3,053
Income from continuing operations and net income	$ 5,464	$ 2,114

The following tables provide certain operating statistics for the Electric and gas utility segment:

Electric Margins
(in thousands)

Customer Base	2006	January 21, 2005 to December 31, 2005
Commercial	$ 7,100	$ 5,773
Residential	8,599	6,915
Industrial	347	437
Municipal	562	416
Total electric	16,608	13,541
Other	590	553
Total margins	$ 17,198	$ 14,094

Gas Margins
(in thousands)

Customer Base	2006	January 21, 2005 to December 31, 2005
Commercial	$ 2,258	$ 1,430
Residential	6,389	4,288
Industrial	495	394
Total gas	9,142	6,112
Other	927	1,027
Total margins	$ 10,069	$ 7,139

	2006	January 21, 2005 to December 31, 2005
Electric sales – MWh	919,938	877,798
Gas sales - Dth	4,387,767	4,062,590

	2006	2005
Heating and cooling degree days:		
Actual		
Heating degree days	6,789	6,622
Cooling degree days	486	443
Variance from normal		
Heating degree days	(8)%	(10)%
Cooling degree days	78%	62%

2006 Rate Increase

On October 3, 2005, the WPSC entered a bench order approving a stipulation and agreement with the Wyoming Office of Consumer Advocate which resulted in an annual revenue increase beginning in 2006. The base rates for retail electric and natural gas service were effective January 1, 2006 and represent increases of 3.65 percent and 5.11 percent in electric and gas revenues, respectively.

2006 Compared to the Period January 21, 2005 to December 31, 2005

Gross margin increased 28 percent primarily due to an increase in base rates, a 5 percent increase in electric demand, an 8 percent increase in gas demand and a full year of operations in 2006. Cooling degree days were 78 percent above normal and heating degree days were 8 percent below normal. We consider gross margin to be the most useful performance measure as fluctuations in cost of gas and electricity flow through to revenues through cost recovery adjustments.

Operating expenses increased 17 percent primarily due to increased depreciation expense, the write-off of uncollectible accounts and increased operating costs due to a full year of operations in 2006.

Income from operations increased $3.4 million primarily due to higher margins and increased income from AFUDC associated with the advancing construction of the Wygen II power plant, partially offset by the increased operating costs.

Wholesale Energy Group

Oil and Gas

Oil and gas operating results were as follows:

	2006	2005 (in thousands)	2004
Revenue	$ 95,078	$ 87,549	$ 59,534
Operating expenses	68,990	55,944	40,353
Operating income	$ 26,088	$ 31,605	$ 19,181
Income from continuing operations	$ 12,736	$ 17,905	$ 12,200

The following tables provide certain operating statistics for the Oil and gas segment.

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

	2006	2005	2004
Bbls of oil sold	401,440	395,550	432,400
Mcf of natural gas sold	12,005,600	11,372,000	10,000,100
Mcf equivalent sales	14,414,240	13,745,300	12,594,600

The following is a summary of LOE/Mcfe at December 31:

	2006	2005	2004
New Mexico	$ 1.38	$ 1.07	$ 1.15
Colorado	$ 1.73	$ —	$ —
All other properties	$ 0.99	$ 0.82	$ 0.85
Total LOE	$ 1.19	$ 0.93	$ 0.97

At the East Blanco Field in New Mexico and our Piceance Basin assets in Colorado, we own and operate the gas gathering system, including associated compression and processing facilities. LOE at our Colorado properties includes approximately $0.49/Mcfe in 2006 and at our New Mexico properties includes approximately $0.71/Mcfe in 2006 and $0.65/Mcfe in 2005 and 2004 for gathering, compression and processing costs.

The following is a summary of our proved oil and gas reserves at December 31:

	2006	2005	2004
Bbls of oil (in thousands)	5,723	6,835	5,239
MMcf of natural gas	164,754	128,573	141,983
Total MMcf equivalents	199,092	169,583	173,417

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. The estimate takes into account 2006 production, the 2006 acquisition of approximately 60 Bcfe, additions of approximately 13 Bcfe and revisions to previous estimates of (29.6) Bcfe. The downward revision to previous estimates was primarily due to lower-than-expected results from certain segments of the 2006 drilling program in the San Juan Basin, and to a lesser extent, well performance at certain areas within our Finn-Shurley field. The decrease in natural gas and oil prices as of December 31, 2006 compared to December 31, 2005 also contributed to the revision.

Reserves reflect year end pricing held constant for the life of the reserves, as follows:

	2006		2005		2004	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 61.05	$ 5.52	$ 61.04	$ 11.23	$ 43.45	$ 6.15
Year-end prices (average well-head)	$ 52.06	$ 5.34	$ 58.52	$ 9.06	$ 41.19	$ 5.55

2006 Compared to 2005

Revenues from oil and gas increased 9 percent for the year ended December 31, 2006 compared to the year ended December 31, 2005. Gas volumes sold increased 6 percent due to increased production from recently completed wells and property acquisitions. Oil volumes sold increased 2 percent due to increased drilling activity in the Finn-Shurley field, partially offset by increased federal royalties deducted as a result of expiring royalty relief on stripper wells. Average natural gas price received, net of hedges and exclusive of gas liquids, for the year ended December 31, 2006 was $6.08/Mcf compared to $6.36/Mcf in the same period of 2005. Average oil price received, net of hedges, for the year ended December 31, 2006 was $48.80/bbl compared to $35.99/bbl in the same period of 2005.

Lease operating expense increased 33 percent primarily due to generally higher field service costs experienced industry-wide and new San Juan compression costs, the East Blanco amine plant costs and operating costs associated with compression and gas treatment for the Piceance Basin properties. The LOE/Mcfe for the year increased 28 percent to $1.19 from $0.93/Mcfe in 2005. Depletion expense per Mcfe increased 26 percent over the prior year to $1.94/Mcfe in 2006 from $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 increased costs from acquisitions and lower reserve estimates.

On March 17, 2006, we acquired certain oil and gas assets of Koch Exploration Company, LLC. The assets include approximately 40 Bcfe of proved reserves, including approximately 31 Bcfe of proved undeveloped reserves which are substantially all gas, and associated midstream and gathering assets. In addition, on August 30, 2006 we acquired from a third party most of the remaining working interests associated with these properties. This includes approximately 22.4 Bcfe of proven reserves, of which 17.9 Bcfe are proved undeveloped reserves. The associated acreage position is located in the Piceance Basin in Colorado.

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.

Additional information on our Oil and Gas operations can be found in Note 23 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Generation

Our power generation segment produced the following results:

	2006	2005	2004
		(in thousands)	
Revenue	$ 154,985	$ 158,399	$ 158,037
Operating expenses	96,168	160,553*	110,103
Operating income (loss)	$ 58,817	$ (2,154)	$ 47,934
Income (loss) from continuing operations	$ 19,901	$ (12,524)	$ 15,562

* Operating expenses in 2005 included a $52.2 million impairment of long-lived assets (see Note 11 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K).

The following table provides certain operating statistics for the Power Generation segment:

	2006	2005	2004
Independent power capacity:			
MW of independent power capacity in service	989	1,000	964
Contracted fleet plant availability:			
Gas-fired plants	92.7%	98.0%	98.8%
Coal-fired plants	95.4%	95.3%	98.2%
Total	93.4%	96.8%	98.6%

2006 Compared to 2005

Revenues for the year ended December 31, 2006 decreased 2 percent from the same period in 2005. Lower revenues are primarily due to scheduled and unscheduled outages for repair and maintenance at the Las Vegas I and Las Vegas II facilities, partially offset by higher capacity revenue at our Harbor facility due to a three year, year-round tolling agreement, which commenced April 1, 2005 and replaced a seasonal contract.

Operating expenses for the year ended December 31, 2006 decreased $64.4 million from the same period in 2005, primarily due to lower variable operating costs and the receipt of $3.9 million of insurance proceeds relating to the Las Vegas II power plant outage; lower variable costs at the Las Vegas I power plant due to lower fuel costs and depreciation expense, and the 2005 $50.3 million impairment charge on the Las Vegas I power plant; a $1.9 million impairment of goodwill relating to certain power fund investments and a $1.6 million charge related to a fuel contract termination. The decrease in operating expense was partially offset by increased repair and maintenance expense, net of insurance proceeds, incurred by the Las Vegas II power plant due to the outage.

Income from continuing operations increased $32.4 million, primarily due to the decrease in operating expense partially offset by an $8.0 million after-tax decrease in earnings from certain power fund investments and increased interest expense due to higher interest rates. In addition, 2005 results were impacted by a $2.8 million charge for a tax adjustment.

Plant availability of our contracted fleet was affected by the planned maintenance at Las Vegas I and unplanned outages at Las Vegas II. The availability of the remainder of our gas-fired fleet was approximately 96.7 percent and availability of our Wygen I coal-fired plant exceeded 95 percent.

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 MW 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 NPC 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 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. 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.

Coal Mining

Coal mining results were as follows:

	2006	2005	2004
		(in thousands)	
Revenue	$ 36,282	$ 34,277	$ 31,967
Operating expenses	29,366	26,385	23,513
Operating income	$ 6,916	$ 7,892	$ 8,454
Income from continuing operations	$ 5,877	$ 6,947	$ 7,463

The following table provides certain operating statistics for the Coal mining segment:

(thousands of tons)	2006	2005	2004
Tons of coal sold	4,717	4,702	4,780
Coal reserves	285,000	290,000	294,000

2006 Compared to 2005

Revenue from our Coal mining segment increased 6 percent for the year ended December 31, 2006 compared to 2005 primarily due to higher average prices received. Tons of coal sold were flat with the prior year as increased train load-out sales were offset by decreased sales to the Wyodak power plant due to scheduled and unscheduled outages.

Operating expenses increased 11 percent for the year ended December 31, 2006 primarily due to increased overburden expense resulting from a change in accounting rules requiring overburden removal to be expensed as incurred, higher depreciation expense and increased mineral taxes, partially offset by lower general and administrative costs.

Income from continuing operations decreased 15 percent primarily due to the increased mining costs partially offset by the increase in revenues.

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.

Energy Marketing

Our energy marketing company produced the following results:

	2006	2005	2004
		(in thousands)	
Revenue -			
Realized gas marketing gross margin	$ 54,088	$ 32,656	$ 26,641
Unrealized gas marketing gross margin	(6,546)	5,066	(1,103)
Realized oil marketing gross margin	2,847	—	—
Unrealized oil marketing gross margin	842	—	—
	51,231	37,722	25,538
Operating expenses	27,223	18,524	14,940
Operating income	$ 24,008	$ 19,198	$ 10,598
Income from continuing operations	$ 17,322	$ 13,836	$ 5,637

The following table provides certain operating statistics for the Energy marketing segment:

	2006	2005	2004
Natural gas physical sales – MMBtu	1,598,200	1,427,400	1,226,600
Crude oil physical sales – Bbls	8,800	—	—

2006 Compared to 2005

Income from continuing operations increased $3.5 million primarily due to higher natural gas marketing margins and a 12 percent increase in physical gas volumes marketed as well as the addition of margins from oil marketing operations beginning in May 2006. Realized gross margins from natural gas marketing for the year ended December 31, 2006 increased $21.4 million over the same period in the prior year. Gas marketing unrealized mark-to-market losses for the year ended December 31, 2006 were $11.6 million higher than the same period in 2005.

Operating expenses increased 47 percent for the year ended December 31, 2006 compared to the same period in 2005 primarily due to increased compensation costs related to higher realized marketing margins and an increase in bad debt provision partially offset by lower professional fees as compared to costs incurred in 2005 related to litigation involving class action lawsuits alleging false reporting of natural gas price and volume information (see Note 18 of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for further discussion of legal proceedings regarding these class action lawsuits).

In March 2006, we sold the operating assets of our Houston, Texas based crude oil marketing and transportation business. Beginning with the first quarter of 2006, the operations of this business were classified as discontinued operations. Crude oil marketing revenues and cost of sales were presented on a gross basis in accordance with accounting standards generally accepted in the United States. Accordingly, the classification to discontinued operations had a significant affect on our consolidated presented revenues and cost of sales. For the years ended December 31, 2005 and 2004, revenues from crude oil marketing and transportation were $778.1 million and $636.6 million; and related cost of sales were $765.2 million and $620.3 million, respectively.

Subsequent to the sale of the crude oil marketing and transportation assets, Enserco, our natural gas marketing subsidiary, began marketing crude oil in the Rocky Mountain region out of our Golden, Colorado offices. Our primary strategy involves executing physical crude oil purchase contracts with producers, and reselling into various markets. These transactions are primarily entered into as back-to-back purchases and sales, effectively locking in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. Under SFAS 133, mark-to-market accounting for the related commodity contracts in our back-to-back strategy results in an acceleration of marketing margins locked in for the term of the contracts. These are generally short-term contracts with automatic renewals if there is no notice of cancellation. (For discussion of potential volatility in energy marketing earnings related to accounting treatment of certain hedging activities at our natural gas and oil marketing operations, see Note 2 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.)

2005 Compared to 2004

Income from continuing operations increased $8.2 million primarily due to higher natural gas marketing margins and volumes 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. 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 expected approximately $2.0 million of the unrealized mark-to-market gain to reverse in 2006. In addition, realized gross margins from natural gas marketing increased $6.0 million.

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. The evaluation for impairment was prompted by plant operating losses driven by high natural gas prices. Natural gas prices were $13.92/MMBtu (NYMEX) on September 30, 2005, and were forecasted to maintain historically high price levels. 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 "Income from discontinued operations, net of income taxes" on the 2004 Consolidated Statement of Income.

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 "ceiling 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, 2006, we can provide no assurance 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 be assured 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.

Derivatives

We account for derivative financial instruments in accordance with 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 their measurement is 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 can provide no assurance 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 17 of our Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, 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.

We account for our Pension and Other Postretirement Benefit Plans under SFAS 87, 106 and 158. SFAS 158 requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position and recognition of changes in the funded status in other comprehensive income for fiscal years ending after December 15, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 will require the measurement of the funded status of the plan to coincide with the date of the year end statement of financial position.

Defined Benefit Pension Plans

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, 2006, 2005 and 2004, we recorded non-cash expense related to our pension plans of approximately $2.8 million, $2.9 million and $2.6 million, respectively.

Our pension plan assets are held in trust and primarily consist of equity and fixed income investments. Fluctuations in actual 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 $6.7 million to $66.0 million for the plan fiscal year ended September 30, 2006. Plan assets earned $8.2 million in 2006. Plan assets increased $6.5 million to $59.3 million as of September 30, 2005. Plan assets earned $8.9 million in 2005. In the recently completed actuarial valuation, for determining our 2007 pension expense, our assumed rate of return on plan assets remained at 8.5 percent. The expected long-term rate of return on plan assets was 8.5 percent, 9.0 percent and 9.5 percent for the 2006, 2005 and 2004 plan years, respectively.

The 8.5 percent assumed rate of return for the 2006 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	75%	9.5%	7.0%
Fixed Income	25%	6.0%	1.5%
Cash	0%	4.0%	0.0%
	100%		8.5%

The Plan's expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for individual asset classes. The asset class weighting is determined using the target allocation for each asset class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from long-term historical returns for the asset class, with adjustments if it is anticipated that long-term future returns will not achieve historical results. The Plan's investment policy for 2006 targets 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 for both the 2006 and 2005 plan years. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns for the S&P 500 Index, which were, at December 31, 2006, 11.8 percent, 12.4 percent, 11.0 percent and 10.6 percent, respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on 10-year treasury bonds of 7.1 percent from 1962 to 2006 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 5.75 percent, 6.0 percent and 6.0 percent in 2006, 2005 and 2004, respectively, for the pension cost determination. In the recently completed actuarial valuation, for determining our 2007 pension expense, we increased the discount rate to 5.95 percent. A 0.20 percent increase in the discount rate would cause annual pension expense to decrease by approximately $0.3 million.

During the first quarter of 2006, a contribution of $1.2 million was made to our Pension Plans. Based on our recently completed plan forecasts, we expect to make additional cash contributions to our Pension Plans of $0.5 million in the 2007 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. Expenses recognized under the plans were $2.2 million in 2006, $2.0 million in 2005 and $2.3 million in 2004. 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 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 results 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, 2006, 2005 and 2004, we recorded other postretirement benefit expense of approximately $1.6 million, $1.8 million and $1.5 million, respectively, in accordance with SFAS 106. Actual payments of benefits to retirees were approximately $0.7 million in 2006 and $0.6 million in 2005 and 2004.

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

Change in Assumption	Impact on December 31, 2006 Accumulated Postretirement Benefit Obligation		Impact on 2006 Service and Interest Cost	
	(in thousands)			
Increase 1%	$	2,819	$	361
Decrease 1%	$	(2,215)	$	(274)

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 2006 expense determination was 10 percent in 2006, decreasing gradually to 5 percent in 2011. The healthcare cost trend rate assumption for 2005 expense determination was 11 percent in 2005, 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 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 determine that we will be 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 is presented in the following table:

Financial Position Summary	2006	2005	Percentage Change
	(in thousands)		
Cash and cash equivalents	$ 37,530	$ 34,198	9.7%
Short-term debt	162,606	66,771	143.5%
Long-term debt	628,340	670,193	(6.2)%
Stockholders' equity	790,041	738,879	6.9%
Ratios			
Long-term debt ratio	44.3%	47.6%	(6.9)%
Total debt ratio	50.0%	49.9%	0.2%

Our dividend payout ratio at December 31, 2006 was approximately 55 percent. 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 2007, we expect payout ratios for 2007 to be in the range of 59 percent to 65 percent.

In 2007, 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. Permanent financing to replace a $1.0 billion bridge facility for our pending acquisition of the Aquila utility assets is expected to come from a combination of new equity, mandatory convertible securities, borrowings under unsecured corporate credit facilities, and cash from internal operations. On February 22, 2007, we completed a private placement common stock offering raising approximately $145.5 million in net proceeds that were used to repay debt.

Cash Flow Activities

2006

In 2006, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions.

Cash flows from operations increased $84.8 million from the prior year amount, affected by a $41.2 million increase in income from continuing operations and by the following:

- A $33.4 million increase in cash flows from the change in current operating assets and liabilities. This is primarily driven by changes in net accounts receivable and accounts payable and $8.5 million more in cash flows due to changes in 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 energy marketing company in the form of storage agreements.

- A $42.0 million increase in deferred income taxes, largely the result of accelerated deductions associated with property, plant and equipment, the tax effect of recognized benefit plan obligations, and higher intangible drilling costs related to increased activity at our oil and gas segment.

- Higher depreciation, depletion and amortization expense of $6.0 million.

- A $50.3 million impairment charge in 2005 for the Las Vegas I power plant included as an expense in 2005, but which did not impact cash flows.

We had cash outflows from investing activities of $268.1 million, including approximately $92.2 million for construction expenditures for Wygen II, $75.4 million for the acquisition of oil and gas assets in the Piceance Basin in Colorado, and expenditures for development drilling of oil and gas properties of approximately $83.4 million and property, plant and equipment additions in the normal course of business, partially offset by $40.7 million cash received for the sale of our Texas based crude oil marketing and transportation assets.

We had cash inflows from financing activities of $11.7 million, primarily due to a $90.5 million increase in borrowings on our revolving bank facility partially offset by the payment of $44.0 million of cash dividends on common stock, the net payment of $21.3 million related to the Black Hills Colorado project level debt refinancing and payment of long-term debt maturities.

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 $23.5 million decrease in income from continuing operations was more than offset by the following:

- An $84.9 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 $15.1 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 $36.2 million increase in the change in current operating assets and liabilities. This is primarily driven by $38.3 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 $36.5 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.

Dividends

Dividends paid on our common stock totaled $1.32 per share in 2006. This reflects an increase in comparison to prior years' dividend levels of $1.28 per share in 2005 and $1.24 per share in 2004. All dividends were paid out of operating cash flows. Our three-year annualized dividend growth rate was 3.2 percent. In February 2007, our board of directors increased the quarterly dividend 3 percent to $0.34 cents per share. If this dividend is maintained during 2007, it will be equivalent to $1.36 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, 2006 we had approximately $36.9 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, 2006, we had $145.5 million of bank borrowings outstanding and $49.4 million of letters of credit issued under this facility, with a remaining borrowing capacity of $205.1 million. Approximately $3.1 million of the cash balance at December 31, 2006 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company.

The $400 million revolving bank 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 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 basis points over the LIBOR (which equated to a 6.02 percent one-month borrowing rate as of December 31, 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 an interest expense 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, 2006, we were in compliance with the above covenants.

Our consolidated net worth was $790.0 million at December 31, 2006, which was approximately $107.8 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, 2006 was 44.3 percent, our total debt leverage ratio was 50.0 percent, our recourse leverage ratio was approximately 50.6 percent and our interest expense coverage ratio was 4.9 to 1.

In addition to the above credit facility, at December 31, 2006, Enserco has a $260.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas and crude oil. The line of credit is secured by all of Enserco's assets and expires on May 10, 2007. At December 31, 2006 there were outstanding letters of credit issued under the facility of $158.7 million, with no borrowing balances on the facility.

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 be assured 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, 2006:

	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)]	$ 644,032	$ 17,106	$ 225,884	$ 30,258	$ 370,784
Unconditional purchase obligations [(d)]	266,495	104,355	45,908	28,231	88,001
Operating lease obligations [(e)]	16,091	1,658	3,753	1,524	9,156
Capital leases [(f)]	85	17	60	8	—
Other long-term obligations [(g)]	29,416	—	—	—	29,416
Employee benefit plans[(h)]	15,586	1,535	3,615	3,219	7,217
Credit facilities	145,500	145,500	—	—	—
Total contractual cash obligations	$ 1,117,205	$ 270,171	$ 279,220	$ 63,240	$ 504,574

(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: $41.8 million in 2007, $36.8 million in 2008, $31.8 million in 2009, $28.9 million in 2010 and $26.0 million in 2011. Variable rate interest is calculated as of December 31, 2006.

(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 an oil and gas drilling rig contract, 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 2006 and price assumptions using existing prices at December 31, 2006. Our transmission obligations are based on filed tariffs as of December 31, 2006. 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 8 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(h) Represents estimated employer contributions to employee benefit plans through the year 2016.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2006, we had guarantees totaling $189.6 million in place. Of the $189.6 million, $165.2 million was related to guarantees associated with subsidiaries' debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets, $20.3 million was related to performance obligations under subsidiary contracts and $4.1 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

As of December 31, 2006, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2006	Year Expiring
Guarantee payments under the Las Vegas I Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	250	2007
Guarantee of payments of Cheyenne Light under various transactions with Tenaska Marketing Ventures	2,000	2007
Guarantee of payments of Cheyenne Light under various transactions with Questar Energy Trading Company	3,000	2007
Guarantee obligations under the Wygen I Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	24,214	2010
Guarantee payments of Las Vegas II to NPC under a power purchase agreement	5,000	2013
Guarantee of Black Hills Colorado project debt for Valmont and Arapahoe plants	30,000	2013
Indemnification for subsidiary reclamation/surety bonds	4,115	Ongoing
	$ 189,597	

Credit Ratings

As of February 28, 2007, our issuer credit rating was "Baa3" by Moody's and "BBB-" by S&P. In addition, Black Hills Power's first mortgage bonds were rated "Baa1" and "BBB" by Moody's and S&P, respectively. In February 2007, Moody's revised the outlook on our credit ratings from stable to negative. In February 2007, S&P affirmed its "BBB-" corporate credit rating on the Company and revised the outlook from negative to stable. If our issuer credit rating should drop below investment grade, pricing under the credit agreements would be affected, increasing annual interest expense by approximately $0.9 million pre-tax based on December 31, 2006 balances.

Capital Requirements

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

	2006	2005	2004
		(in thousands)	
Acquisition costs:			
Payment for acquisition of net assets, net of cash acquired	$ —	$ 65,118	$ —
Property additions:			
Retail services –			
Electric utility	24,992	18,162	13,347
Electric and gas utility*	107,348	30,536	—
Wholesale energy –			
Oil and gas**	158,846	71,799	53,891
Power generation	8,557	6,095	6,043
Coal mining	5,807	6,517	3,183
Energy marketing	928	80	360
Corporate	1,972	3,090	5,787
	308,450	136,279	82,611
Discontinued operations	—	7,459	8,363
	308,450	143,738	90,974
Common and preferred stock dividends	43,960	42,212	40,531
Maturities/redemptions of long-term debt	36,518	94,171	155,021
	$ 388,928	$ 345,239	$ 286,526

* Includes $92.2 million in 2006 and $23.8 million in 2005 for Wygen II construction.
** Includes $75.4 million in 2006 for acquisitions in the Piceance Basin in Colorado.

Our capital additions for 2006 were $308.5 million. The capital expenditures were primarily for construction of the Wygen II power plant, acquisitions and development drilling of oil and gas properties and maintenance capital.

Our capital additions for 2005 were $208.9 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.

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

	2007	2008	2009
		(in thousands)	
Retail services:*			
Electric utility	$ 22,000	$ 29,099	$ 28,077
Electric and gas utility**	49,327	15,470	15,460
Wholesale energy:			
Oil and gas	72,100	89,760	89,160
Power generation	730	7,570	8,150
Coal mining	4,850	9,000	10,040
Energy marketing	1,800	1,000	140
Corporate	2,805	—	—
Unspecified development capital	5,000	70,000	120,000
	$ 158,612	$ 221,899	$ 271,027

* Forecasted capital requirements are exclusive of the $940.0 million purchase price and related other costs for the pending acquisition of Aquila utility assets.

** Regulated electric and gas utility capital requirements include approximately $34.6 million for the development of the Wygen II coal-fired plant in 2007.

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 business, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of 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 6 and 7 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 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, which includes 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 and crude oil 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 end-use 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 and crude oil.

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 CRPP as approved by the Executive Risk Committee.

Monitoring and Reporting Market Risk Exposures

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our natural gas and oil marketing portfolio. We limit and monitor our market risk through established limits on the nominal size of positions based on type of trade, location and duration. Such limits include those on fixed price, basis, index, storage, transportation and foreign exchange positions and on the aggregate portfolio VaR.

Our market risk limits are monitored by our Risk Management function to ensure compliance with our stated risk limits. The Risk Management function operates independently from our energy marketing group. The limits are measured and monitored at a minimum each business day and are regularly reported to and reviewed by our Executive Risk Committee.

We measure and monitor the market risk inherent in the natural gas trading portfolio employing 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. In addition to VaR and scenario analysis, risk management daily activities include scrutinizing positions, assessing changes in daily mark-to-market and other non-statistical risk management techniques.

The contract or notional amounts, terms and mark-to-market values of our natural gas marketing and derivative commodity instruments at December 31, 2006 and 2005, are set forth in Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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, 2006 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2005	$ 5,879[(a)]
Net cash settled during the year on positions that existed at December 31, 2005	(16,280)
Unrealized gain on new positions entered during the year and still existing at December 31, 2006	(1,669)
Realized gain on positions that existed at December 31, 2005 and were settled during the year	10,156
Unrealized loss on positions that existed at December 31, 2005 and still exist at December 31, 2006	460
	(7,333)
Total fair value of energy marketing positions marked-to-market at December 31, 2006	$ (1,454)[(a)]

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(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, 2006	December 31, 2005
Net derivative assets/(liabilities)	$ 30,059	$ (764)
Fair value adjustment recorded in material, supplies and fuel	(31,513)	6,643
	$ (1,454)	$ 5,879

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, 2006, we had a mark to fair value unrealized loss of $(1.5) million for our natural gas and crude oil marketing activities. Of this amount, $(1.1) million was current and $(0.4) million was non-current. The sources of fair value measurements were as follows (in thousands):

	Maturities		
Source of Fair Value	2007	2008 and Thereafter	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ (950)	$ (494)	$ (1,444)
Prices provided by other external sources	(132)	122	(10)
Modeled	—	—	—
Total	$ (1,082)	$ (372)	$ (1,454)

The following table presents a reconciliation of our energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing 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 GAAP 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.

	December 31, 2006	December 31, 2005
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ (1,454)	$ 5,879
Increase 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	24,574	13,901
Fair value of all forward positions (non-GAAP)	23,120	19,780
"Liquidity reserve" included in GAAP marked-to-market fair value	1,897	1,244
Fair value of all forward positions excluding "Liquidity reserve" (non-GAAP)	$ 25,017	$ 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.

To mitigate commodity price risk and preserve cash flows, we primarily use over-the-counter swaps and options. Our hedging policy allows up to 75 percent of our natural gas and 80 percent of our crude oil production from proven producing reserves to be hedged for a period up to two years in the future. Our hedging strategy is conducted from an enterprise-wide risk perspective; accordingly, we may not externally hedge a portion of our natural gas production when we have offsetting price risk for the fuel requirements of our power generating activities.

The Company has entered into agreements to hedge a portion of its estimated 2007, 2008 and 2009 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	12/14/2005	Swap	11/06 – 03/07	5,000	$ 10.25
San Juan El Paso	04/03/2006	Swap	11/06 – 03/07	5,000	$ 8.50
San Juan El Paso	04/03/2006	Swap	04/07 – 10/07	5,000	$ 7.46
San Juan El Paso	06/02/2006	Swap	04/07 – 10/07	2,500	$ 7.20
San Juan El Paso	06/15/2006	Swap	11/06 – 03/07	2,500	$ 8.52
San Juan El Paso	06/15/2006	Swap	11/06 – 03/07	2,500	$ 8.59
CIG	07/28/2006	Swap	09/06 – 03/08	2,500	$ 7.60
CIG	07/31/2006	Swap	09/06 – 03/08	2,500	$ 7.85
San Juan El Paso	11/03/2006	Swap	04/07 – 10/07	5,000	$ 6.91
San Juan El Paso	11/03/2006	Swap	11/07 – 03/08	5,000	$ 7.86
San Juan El Paso	11/29/2006	Swap	04/07 – 10/07	500	$ 7.10
San Juan El Paso	11/29/2006	Swap	11/07 – 12/07	5,000	$ 7.82
San Juan El Paso	11/29/2006	Swap	01/08 – 12/08	5,000	$ 7.44
San Juan El Paso	11/29/2006	Swap	11/07 – 12/08	3,000	$ 7.49
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	2,500	$ 6.93
San Juan El Paso	01/04/2007	Swap	04/08 – 03/09	1,000	$ 6.96
San Juan El Paso	01/05/2007	Swap	01/09 – 03/09	1,500	$ 7.51
San Juan El Paso	01/10/2007	Swap	04/08 – 12/08	1,500	$ 6.88
San Juan El Paso	01/11/2007	Swap	04/08 – 12/08	2,000	$ 6.81
San Juan El Paso	02/12/2007	Swap	01/09 – 03/09	5,000	$ 7.87

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
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
NYMEX	04/03/2006	Put	Calendar 2007	5,000	$ 70.00
NYMEX	01/30/2007	Swap	Calendar 2008	5,000	$ 61.38
NYMEX	02/20/2007	Put	Calendar 2008	5,000	$ 60.00

The hedge agreements entered into by the Company had a fair value of approximately $15.2 million as of December 31, 2006.

Power Generation

We have a portfolio of gas-fired generation assets located throughout several Western states. The outputs 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, 2006, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 9.75 years. Further details of the swap agreements are set forth in Note 2 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2006 and 2005, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2006	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax (Loss)
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102	$ —
December 31, 2005									
Interest rate swaps	$ 163,000	4.43%	10.00	$ 13	$ —	$ 76	$ 230	$ (249)	$ (44)

We anticipate a portion of unrealized income recorded in accumulated other comprehensive income will be realized as increased interest income in 2007. Based on December 31, 2006 market interest rates, a gain of approximately $0.2 million would be realized and reported in pre-tax earnings during 2007. Estimated and realized amounts will likely change during 2007 as market interest rates change.

At December 31, 2006, we had $259.1 million of outstanding, variable-rate, long-term debt of which $109.1 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 pre-tax interest expense to increase $1.1 million in 2007.

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):

	2007	2008	2009	2010	2011	Thereafter	Total
Cash equivalents							
Fixed rate	$ 36,939	$ —	$ —	$ —	$ —	$ —	$ 36,939
Long-term debt							
Fixed rate [(a)]	$ 2,249	$ 2,262	$ 2,278	$ 32,296	$ 2,316	$ 343,513	$ 384,914
Average interest rate	9.38%	9.41%	9.44%	8.16%	9.51%	7.19%	7.31%
Variable rate [(b)]	$ 14,857	$ 143,121	$ 14,857	$ 31,070	$ 12,857	$ 42,356	$ 259,118
Average interest rate	6.39%	6.03%	6.39%	6.89%	6.24%	5.23%	6.05%
Total long-term debt	$ 17,106	$ 145,383	$ 17,135	$ 63,366	$ 15,173	$ 385,869	$ 644,032
Average interest rate	6.78%	6.08%	6.79%	7.54%	6.73%	6.97%	6.80%

(a) Excludes unamortized premium or discount.
(b) Approximately 58 percent of the variable rate long-term debt has been hedged with interest rate swaps converting the floating rates to fixed rates with an average interest rate of 5.04 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 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, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

For our energy marketing, production, and generation activities, we seek 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 primarily with investment grade companies. Approximately 70 percent of our credit exposure was with investment grade companies. Of the remaining 30 percent credit exposure with non-investment grade rated counterparties, approximately 48 percent of this exposure was supported through letters of credit or prepayments, and the remaining primarily unsecured.

Foreign Exchange Contracts

Our natural gas and crude oil 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, 2006 and 2005, we had outstanding forward exchange contracts to sell approximately $0 and $29.0 million Canadian dollars, respectively. At December 31, 2006 and 2005, we also had outstanding forward exchange contracts to purchase approximately $44.0 million and $88.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.3) million and $(1.0) million at December 31, 2006 and 2005, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2006 settled by February 26, 2007.

New Accounting Pronouncements

See Note 1 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2006 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, 2006, 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, 2006.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 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

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF 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, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2006, 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, 2006, 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, 2006, of the Corporation, and our report dated February 27, 2007, expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Corporation's adoption of Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, effective January 1, 2006, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, effective as of December 31, 2006.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF BLACK HILLS CORPORATION:

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Corporation") as of December 31, 2006 and 2005, 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, 2006. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Corporation adopted Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, effective January 1, 2006, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, effective as of December 31, 2006.

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, 2006, 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 February 27, 2007, 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.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 27, 2007

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2006	2005	2004
	(in thousands, except per share amounts)		
Revenues:			
Operating revenues	$ 656,882	$ 613,541	$ 445,543
Operating expenses:			
Fuel and purchased power	203,473	189,752	82,920
Operations and maintenance	78,944	75,977	75,889
Administrative and general	91,883	91,246	57,890
Depreciation, depletion and amortization	94,083	88,116	72,979
Taxes, other than income taxes	35,827	34,424	27,195
Impairment of long-lived assets (Notes 1 and 11)	—	52,175	—
	504,210	531,690	316,873
Operating income	152,672	81,851	128,670
Other income (expense):			
Interest expense	(51,026)	(48,633)	(48,092)
Interest income	1,781	1,717	1,698
Allowance for funds used during construction - equity	2,647	—	—
Other expense	(155)	(290)	(484)
Other income	786	1,143	1,160
	(45,967)	(46,063)	(45,718)
Income from continuing operations before minority interest and income taxes	106,705	35,788	82,952
Equity in earnings of unconsolidated subsidiaries	1,653	14,325	(386)
Minority interest	(510)	(277)	(186)
Income taxes	(33,802)	(17,044)	(26,099)
Income from continuing operations	74,046	32,792	56,281
Income from discontinued operations, net of income taxes	6,973	628	1,692
Net income	81,019	33,420	57,973
Preferred stock dividends	—	(159)	(321)
Net income available for common stock	$ 81,019	$ 33,261	$ 57,652
Earnings per share of common stock:			
Basic-			
Continuing operations	$ 2.23	$ 1.00	$ 1.73
Discontinued operations	0.21	0.02	0.05
Total	$ 2.44	$ 1.02	$ 1.78
Diluted-			
Continuing operations	$ 2.21	$ 0.98	$ 1.71
Discontinued operations	0.21	0.02	0.05
Total	$ 2.42	$ 1.00	$ 1.76
Weighted average common shares outstanding:			
Basic	33,179	32,765	32,387
Diluted	33,549	33,288	32,912

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2006	2005
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 36,939	$ 31,817
Restricted cash	2,004	—
Accounts receivable (net of allowance for doubtful accounts of $4,202 and $4,685, respectively)	263,109	264,695
Materials, supplies and fuel	92,560	122,521
Derivative assets	69,244	20,681
Other current assets	9,221	7,855
Assets of discontinued operations	1,424	122,158
	474,501	569,727
Investments	23,808	27,558
Property, plant and equipment	2,242,396	1,928,559
Less accumulated depreciation and depletion	(596,029)	(518,525)
	1,646,367	1,410,034
Other assets:		
Goodwill	30,563	29,847
Intangible assets, net	24,429	27,548
Derivative assets	2,871	1,898
Other	42,137	53,646
	100,000	112,939
	$ 2,244,676	$ 2,120,258
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 224,009	$ 202,639
Accrued liabilities	95,020	72,514
Derivative liabilities	24,041	26,141
Accrued income taxes	19,561	11,650
Deferred income taxes	1,215	1,456
Notes payable	145,500	55,000
Current maturities of long-term debt	17,106	11,771
Liabilities of discontinued operations	2,526	92,818
	528,978	473,989
Long-term debt, net of current maturities	628,340	670,193
Deferred credits and other liabilities:		
Deferred income taxes	174,332	134,533
Derivative liabilities	1,530	2,623
Other	116,297	95,116
	292,159	232,272
Minority interest	5,158	4,925
Commitments and contingencies (Notes 6, 7, 8, 13, 17, 18 and 19)		
Stockholders' equity:		
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 33,404,902 shares in 2006 and 33,222,522 shares in 2005	33,405	33,223
Additional paid-in capital	409,826	404,035
Retained earnings	348,245	313,217
Treasury stock at cost – 35,700 shares in 2006 and 66,938 shares in 2005	(920)	(1,766)
Accumulated other comprehensive loss	(515)	(9,830)
	790,041	738,879
	$ 2,244,676	$ 2,120,258

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,	2006	2005	2004
		(in thousands)	
Operating activities:			
Net income	$ 81,019	$ 33,420	$ 57,973
Income from discontinued operations, net of tax	(6,973)	(628)	(1,692)
Income from continuing operations	74,046	32,792	56,281
Adjustments to reconcile income from continuing operations to net cash provided by operating activities-			
Depreciation, depletion and amortization	94,083	88,116	72,979
Impairment of long-lived assets	—	52,175	—
Issuance of common stock and treasury stock for operating expense	2,760	1,917	1,030
Net change in derivative assets and liabilities	8,864	(6,536)	2,541
Deferred income taxes	33,233	(8,783)	27,674
Allowance for funds used during construction – equity	2,647	—	—
Change in operating assets and liabilities-			
Materials, supplies and fuel	(8,300)	(16,787)	(55,066)
Accounts receivable and other current assets	2,208	(46,333)	(35,898)
Accounts payable and other current liabilities	28,853	52,515	44,154
Regulatory assets and liabilities	18,879	17,254	(2,995)
Other operating activities	4,984	7,278	15,228
Net cash provided by operating activities of continuing operations	262,257	173,608	125,928
Net cash (used in) provided by operating activities of discontinued operations	(2,562)	1,241	11,077
Net cash provided by operating activities	259,695	174,849	137,005
Investing activities:			
Property, plant and equipment additions	(308,450)	(136,279)	(82,611)
Proceeds from sale of business operations	40,735	103,010	500
Payment for acquisition of net assets, net of cash acquired	—	(65,118)	—
Other investing activities	(1,154)	(3,861)	(2,392)
Net cash used in investing activities of continuing operations	(268,869)	(102,248)	(84,503)
Net cash provided by (used in) investing activities of discontinued operations	772	(7,459)	(8,363)
Net cash used in investing activities	(268,097)	(109,707)	(92,866)
Financing activities:			
Dividends paid on common and preferred stock	(43,960)	(42,212)	(40,531)
Common stock issued	4,059	12,212	4,031
Increase in short-term borrowings, net	90,500	31,000	24,000
Long-term debt – issuance	90,000	—	18,650
Long-term debt – repayments	(126,518)	(94,171)	(155,021)
Other financing activities	(2,347)	(2,279)	(3,519)
Net cash provided by (used in) financing activities of continuing operations	11,734	(95,450)	(152,390)
Net cash provided by financing activities of discontinued operations	—	—	—
Net cash provided by (used in) financing activities	11,734	(95,450)	(152,390)
Increase (decrease) in cash and cash equivalents	3,332	(30,308)	(108,251)
Cash and cash equivalents:			
Beginning of year	34,198[b]	64,506[c]	172,757[d]
End of year	$ 37,530[a]	$ 34,198[b]	$ 64,506[c]
Supplemental disclosure of cash flow information:			
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$ 25,029	$ 13,270	$ —
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 48,905	$ 47,987	$ 49,546
Income taxes paid (refunded)	$ (2,685)	$ 12,743	$ (21,927)

(a) Includes approximately $0.6 million at December 31, 2006 of cash included in the assets of discontinued operations.
(b) Includes approximately $2.4 million at December 31, 2005 of cash included in the assets of discontinued operations.
(c) Includes approximately $8.6 million at December 31, 2004 of cash included in the assets of discontinued operations.
(d) Includes approximately $5.9 million at December 31, 2003 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		Additional Paid-In	Retained	Treasury Stock		Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Shares	Amount	Income (Loss)	Total
				(in thousands)				
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 15)	—	—	—	—	—	—	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 15)	—	—	—	—	—	—	(2,223)	(2,223)
Total comprehensive income (loss)	—	—	—	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
Comprehensive Income:								
Net income	—	—	—	81,019	—	—	—	81,019
Other comprehensive income, net of tax (see Note 15)	—	—	—	—	—	—	15,429	15,429
Total comprehensive income	—	—	—	81,019	—	—	15,429	96,448
Dividends on common stock	—	—	—	(43,960)	—	—	—	(43,960)
Adoption of accounting pronouncement (see Note 17)	—	—	—	—	—	—	(6,114)	(6,114)
Cumulative effect of change in accounting principle (see Note 1)	—	—	—	(2,031)	—	—	—	(2,031)
Issuance of common stock	182	182	5,791	—	—	—	—	5,973
Treasury stock issued, net	—	—	—	—	(31)	846	—	846
Balance at December 31, 2006	33,405	$ 33,405	$ 409,826	$ 348,245	36	$ (920)	$ (515)	$ 790,041

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

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2006, 2005 and 2004

(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, and public utility electric and gas operations through its subsidiary, Cheyenne Light, which was acquired on January 21, 2005 (see Note 21). The Company operates its wholesale energy businesses through its direct and indirect subsidiaries: BHEP related to oil and natural gas production; Black Hills Generation and its subsidiaries and Black Hills Wyoming related to independent power activities; WRDC related to coal; Enserco related to natural gas and crude oil marketing; all aggregated for reporting purposes as Black Hills Energy. For further descriptions of the Company's business segments, see Note 20.

In March 2006, the Company sold the operating assets of BHER and related subsidiaries, the Company's crude oil marketing and transportation business. 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. Amounts related to Black Hills Energy Resources, Black Hills FiberSystems, Pepperell and Landrica are included in Discontinued operations on the accompanying Consolidated Financial Statements. See Note 16 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 VIE in which the Company is the primary beneficiary as defined by 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 SFAS 71. Total intercompany fuel sales not eliminated were $10.8 million, $10.1 million and $9.6 million in 2006, 2005 and 2004, 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 BHEP gas processing plant as discussed in Note 5.

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

	2006	2005
	(in thousands)	
Major Classification		
Materials and supplies	$ 31,946	$ 24,567
Fuel	9,663	7,544
Gas and oil held by energy marketing	50,951	90,410
Total materials, supplies and fuel*	$ 92,560	$ 122,521

* As of December 31, 2006 and 2005, market adjustments related to gas and oil held by energy marketing and recorded in inventory, were $(31.5) million and $6.6 million, respectively. (See Note 2 for further discussion of energy marketing trading activities.)

"Materials and supplies" and "Fuel" are stated at the lower of cost or market on a weighted-average cost basis.

"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 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 undeveloped leasehold costs and certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $7.2 million, $0.7 million and $0.2 million in 2006, 2005 and 2004, 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.

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 2006, 2005 or 2004.

Goodwill and Intangible Assets

The Company accounts for goodwill and intangible assets in accordance with 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, 2006 and 2005 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2004, net of accumulated amortization	$ 28,455	$ 36,363
Additions	3,915	3
Impairment losses	(1,897)	(5,567)
Acquisition-related tax adjustment	(626)	—
Amortization expense	—	(3,251)
Balance at December 31, 2005, net of accumulated amortization	$ 29,847	$ 27,548
Additions	716	—
Amortization expense	—	(3,119)
Balance at December 31, 2006, net of accumulated amortization	$ 30,563	$ 24,429

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 $50.3 million, with accumulated amortization of $25.9 million at December 31, 2006 and $50.2 million, with accumulated amortization of $22.7 million at December 31, 2005. Amortization expense for intangible assets was $3.1 million, $3.3 million and $3.3 million in 2006, 2005 and 2004, 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 and $0.4 million in 2011.

Additions to goodwill in 2006 and 2005 relate to the acquisition of Cheyenne Light and represent the cost of the investment over the estimated fair value of the underlying net assets acquired (see Note 21).

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 recorded an impairment charge for 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 11).

Asset Retirement Obligations

The Company records liabilities for the present value of retirement costs for which the Company has a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations. For the oil and gas segment, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties.

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 (see Note 16).

Derivatives and Hedging Activities

The Company accounts for its derivative and hedging activities in accordance with SFAS 133. SFAS 133 requires that derivative instruments be recorded on 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 and crude oil 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 Statement of Income.

Legal Costs

Litigation liabilities, including potential settlements are recorded when it is probable the Company is likely to incur liability or settlement costs, and those costs can be reasonably estimated. Litigation settlement accruals are recorded net of expected insurance recovery. Legal costs related to ongoing litigation 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 FIN 46.

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 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 or Cheyenne Light 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.

At December 31, 2006 and 2005, the Company had regulatory assets of $19.4 million and $17.3 million and regulatory liabilities of $32.2 million and $18.4 million, respectively. Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with regulated utilities' defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and unamortized losses on reacquired debt. Regulatory liabilities include the probable future decrease in rate revenues related to decreases in purchased power, transmission and natural gas costs charged to Cheyenne Light customers through an ECA and GCA mechanism, a decrease in deferred tax liabilities for prior reductions in statutory federal income tax rates, gains associated with regulated utilities' defined benefit postretirement plans and the cost of removal for utility plant, recovered through the Company's electric utility rates.

Each year Cheyenne Light files with the 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 asset or liability, respectively. As of December 31, 2006, the Company had a deferred energy liability balance. The increase in regulatory liabilities in 2006 is primarily due to ECA and GCA liabilities for over-recovered energy costs at Cheyenne Light. The regulatory assets are included in Other assets and the regulatory liabilities are included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets.

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance a project. AFUDC for the years ended December 31, 2006, 2005 and 2004 was $5.6 million, $0.7 million, and $0.2 million, respectively. The equity component of AFUDC for 2006, 2005 and 2004 was $2.6 million, $0.4 million and $0.1 million, respectively. The borrowed funds component of AFUDC for 2006, 2005 and 2004 was $3.0 million, $0.3 million and $0.1 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is included in Interest expense on the accompanying Consolidated Statements of Income.

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 as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. The Company classifies deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

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 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 91-6, or in accordance with 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 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 99-19. Accordingly, gains and losses (realized and unrealized) on transactions at the Company's natural gas and crude oil marketing operations are presented on a net basis in operating revenues, whether or not settled physically.

Earnings per Share of Common Stock

Basic earnings per share from continuing operations is computed by dividing "Income from continuing operations" less preferred stock 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):

	2006		2005		2004	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 74,046		$ 32,792		$ 56,281	
Less: preferred stock dividends	—		(159)		(321)	
Basic – Income from continuing operations	74,046	33,179	32,633	32,765	55,960	32,387
Dilutive effect of:						
Stock options	—	87	—	160	—	96
Convertible preferred stock	—	—	159	97	321	195
Contingent shares issuable for prior acquisition	—	159	—	159	—	159
Others	—	124	—	107	—	75
Diluted – Income from continuing operations	$ 74,046	33,549	$ 32,792	33,288	$ 56,281	32,912

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):

	2006	2005	2004
Options to purchase common stock	153	123	484

Recently Adopted Accounting Pronouncements

SFAS 158

During September 2006, the FASB issued SFAS 158. This Statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position, and provides for related disclosures. SFAS 158 is effective for the recognition of the funded status as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income and the related disclosures in financial statements issued for fiscal years ending after December 15, 2006.

The Company applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 will require the measurement of the funded status of the plan to coincide with the date of the year end statement of financial position. See Note 17, "Employee Benefit Plans," for further discussion of Defined Benefit Pension and Other Postretirement Plans.

SFAS 123 (R)

On December 16, 2004, the FASB issued SFAS 123(R), which is a revision of SFAS 123. 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 previously accounted for its employee equity compensation stock option plans under the provisions of APB 25 and no stock-based employee compensation cost was reflected in net income for stock options.

As of January 1, 2006, the Company applied the provisions of 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 were outstanding at the date of adoption. Adoption of SFAS 123(R) did not have a significant effect on the Company's consolidated financial position, results of operations or cash flows. See Note 9, Common and Preferred Stock, for further discussion of stock-based compensation plans.

EITF 04-6

On March 17, 2005, the EITF issued 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. Upon adoption of EITF 04-6 on January 1, 2006, the Company recorded a $2.0 million cumulative effect adjustment to write-off previously recorded deferred charges, with the offset decreasing retained earnings. Additionally, since January 1, 2006, stripping costs are expensed at the time incurred.

EITF 04-13

On September 28, 2005, the FASB ratified the consensus reached under EITF 04-13, which determines if accounting for purchases and sales of inventory with the same counterparty 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 did not have a significant effect on the Company's consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

SFAS 157

During September 2006, the FASB issued SFAS 157 and applies under other accounting pronouncements that require or permit fair value measurements. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Management is currently evaluating the impact SFAS 157 will have on the Company's consolidated financial statements.

SFAS 159

In February 2007, the FASB issued SFAS 159, which establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. Management is currently evaluating the impact SFAS 159 will have on the Company's consolidated financial statements.

FIN 48

During June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the impact of adoption to be reported as a cumulative effect of an accounting change. Management is currently evaluating the impact FIN 48 will have on the Company's consolidated financial statements.

SAB No. 108 – Effects of Prior Year Misstatements on Current Year Financial Statements

During September 2006, the staff of the SEC released SAB No. 108 on Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 provides guidance on how the effects of the carryover or reversal of prior year financial statement misstatements should be considered in quantifying a current year misstatement. Prior practice allowed the evaluation of materiality on the basis of (1) the error quantified as the amount by which the current year income statement was misstated (rollover method) or (2) the cumulative error quantified as the cumulative amount by which the current year balance sheet was misstated (iron curtain method). Reliance on either method in prior years could have resulted in misstatement of the financial statements. The guidance provided in SAB No. 108 requires both methods to be used in evaluating materiality. Immaterial prior year errors may be corrected with the first filing of prior year financial statements after adoption. The cumulative effect of the correction can either be reported in the carrying amounts of assets and liabilities as of the beginning of that fiscal year, and the offsetting adjustment made to the opening balance of retained earnings for that year, or by restating prior periods. Disclosure requirements include the nature and amount of each individual error being corrected in the cumulative adjustment, as well as a disclosure of when and how each error being corrected arose and the fact that the errors had previously been considered immaterial. SAB No. 108 is effective January 1, 2007. SAB No. 108 did not have an effect on the Company's 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 6 and 7; 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 its 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 and Crude Oil Marketing

To manage its 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. Energy marketing business activities are conducted within the parameters as defined and allowed by the BHCRPP.

For the years ended December 31, 2006, 2005 and 2004, contracts and other activities at the Company's natural gas and crude oil marketing operations are accounted for under the provisions of EITF 02-3 and SFAS 133. As such, all of the contracts and other activities at the Company's natural gas and crude oil 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 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 and crude oil 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 and crude oil marketing positions are economically hedged, the Company is required to mark some parts of its overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of its economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions should be expected given these accounting requirements.

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

	2006		2005	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu)				
Natural gas basis swaps purchased	138,111	22	43,507	22
Natural gas basis swaps sold	148,720	22	53,665	22
Natural gas fixed-for-float swaps purchased	38,239	16	17,083	23
Natural gas fixed-for-float swaps sold	59,061	15	24,871	23
Natural gas physical purchases	87,782	48	59,855	34
Natural gas physical sales	106,500	48	88,302	46
Natural gas options purchased	22,373	15	6,176	21
Natural gas options sold	22,373	15	6,176	21
(Bbls of oil)				
Crude oil physical purchases	1,600	4	—	—
Crude oil physical sales	1,367	7	—	—
Crude oil swaps purchased	240	12	—	—
Crude oil swaps sold	240	12	—	—
(Dollars, in thousands)				
Canadian dollars purchased	$44,000	1	$88,000	2
Canadian dollars sold	$ —	—	$29,000	5

Derivatives and certain natural gas and oil marketing activities were marked to fair value on December 31, 2006 and 2005, 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, 2006 and 2005 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (Loss)
December 31, 2006	$ 53,728	$ 4	$ 23,296	$ 377	$ 30,059
December 31, 2005	$ 20,326	$ 1,747	$ 20,751	$ 2,086	$ (764)

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 Consolidated Balance Sheets and unrealized gain/loss on the Consolidated Statements of Income. As of December 31, 2006 and 2005, the market adjustments recorded in inventory were $(31.5) million and $6.6 million, respectively.

Activities Other than Trading

Oil and Gas Exploration and Production

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

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

At December 31, 2006 and 2005, the Company had a portfolio of swaps to hedge portions of its crude oil and natural gas production. These transactions were designated at inception 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, 2006 and 2005, 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, 2006 and 2005 the Company had the following swaps, options and related balances (in thousands):

December 31, 2006	Notional*	Maximum Duration in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	(Loss) Earnings
Crude oil swaps/options	240,000	2.00	$ 524	$ —	$ 362	$ —	$ 36	$ 126
Natural gas swaps	10,588,000	1.25	13,485	2,000	309	175	15,339	(338)
			$ 14,009	$ 2,000	$ 671	$ 175	$ 15,375	$ (212)
December 31, 2005								
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

*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 currently recorded in accumulated other comprehensive income will be realized in earnings during 2007. Based on December 31, 2006 market prices, a $13.1 million gain will be realized and reported in earnings during 2007. These estimated realized gains for 2007 were calculated using December 31, 2006 market prices. Estimated and actual realized gains will likely change during 2007 as market prices change.

Fuel in Storage

On December 31, 2006 and 2005, the Company had the following swaps and related balances (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Unrealized Gain
December 31, 2006								
Natural gas swaps	380,000	0.25	$ 1,220	$ —	$ —	$ —	$ 878	$ 342
December 31, 2005								
Natural gas swaps	275,000	0.25	$ 192	$ —	$ 219	$ —	$ (219)	$ 192

*gas in MMBtu

Based on December 31, 2006 market prices, a $0.9 million gain would be realized and reported in pre-tax earnings during the next twelve months related to the cash flow hedge. These estimated realized gains for the next twelve months were calculated using December 31, 2006 market prices. Estimated and actual realized gains 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, 2006 and 2005, the market adjustments recorded in inventory were $(0.3) million and $(0.2) million, respectively.

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, the Company does 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 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, 2006, the Company had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 9.75 years and a fair value of $0.1 million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2006 and 2005 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 Income (Loss)	Pre-tax (Loss)
December 31, 2006									
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102	$ —
December 31, 2005									
Interest rate swaps	$ 163,000	4.43%	10	$ 13	$ —	$ 76	$ 230	$ (249)	$ (44)

The Company anticipates a portion of unrealized gains recorded in accumulated other comprehensive income will be realized as increased interest income in 2007. Based on December 31, 2006 market interest rates, a gain of approximately $0.2 million would be realized and reported in pre-tax earnings during 2007. Estimated and realized amounts will likely change during 2007 as market interest rates change.

At December 31, 2006, the Company had $259.1 million of outstanding, variable-rate, long-term debt of which $109.1 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 pre-tax interest expense to increase $1.1 million in 2007.

In June 2005, the Company repaid approximately $81.5 million of project level financing on its Fountain Valley power facility. The Company had an interest rate swap with a $25.0 million notional amount that matured in September 2006, which 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.

Foreign Exchange Contracts

The Company's gas marketing subsidiary conducts its business in the United States as well as 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, 2006 and 2005, the Company had outstanding forward exchange contracts to sell of approximately $0 and $29.0 million Canadian dollars, respectively. At December 31, 2006 and 2005, the Company also had outstanding forward exchange contracts to purchase approximately $44.0 million and $88.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.3) million and $(1.0) million at December 31, 2006 and 2005, respectively, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. The impact of foreign exchange transactions did not have a material effect on the Company's Consolidated Statements of Income. All forward exchange contracts outstanding at December 31, 2006 settle by February 26, 2007.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. The Company adopted the 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 which includes 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 the regulated utilities) was concentrated primarily among investment grade companies. Approximately 70 percent of the credit exposure was with investment grade companies. Of the remaining 30 percent credit exposure with non-investment grade rated counterparties, approximately 48 percent of this exposure was supported through letters of credit or prepayments and the remaining primarily unsecured.

(3) INVESTMENTS IN ASSOCIATED COMPANIES

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

- A 3.7 percent, 5.7 percent 4.5 percent and 4.3 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. The Company's carrying amount of its investment in the funds is $5.5 million and $10.8 million, as of December 31, 2006 and 2005, respectively. As of, and for the year ended December 31, 2006, the funds had assets of $72.0 million, liabilities of $0.3 million and net income of $14.3 million. 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. 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 recorded an impairment charge for the related goodwill.

  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.

- A 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The Company's carrying amount in the investment is $4.4 million and $4.3 million as of December 31, 2006 and 2005, respectively, which includes $0.7 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, 2006, these projects had assets of $18.6 million, liabilities of $9.9 million and net income of $0.6 million. 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.

(4) PROPERTY, PLANT AND EQUIPMENT

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

Retail services

Electric Utility	2006	2006 Weighted Average Useful Life	2005	2005 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 325,616	47	$ 317,792	45	25-58
Transmission	70,731	45	69,998	45	35-50
Distribution	232,299	37	222,305	32	20-40
Plant acquisition adjustment	4,870	—	4,870	—	—
General	34,533	22	31,678	18	7-40
Total electric plant	668,049		646,643		
Less accumulated depreciation and amortization	265,247		250,583		
Electric plant net of accumulated depreciation and amortization	402,802		396,060		
Construction work in progress	7,586		6,684		
Net electric plant	$ 410,388		$ 402,744		

Electric and Gas Utility	2006	2006 Weighted Average Useful Life	2005	2005 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Transmission	$ 2,489	44	$ 2,283	40	35-50
Electric distribution	68,779	44	60,620	40	20-40
General	227	27	95	25	7-40
Gas plant:					
Distribution	37,955	56	36,109	55	10-65
General	135	27	72	25	25
General	7,360	27	5,505	31	3-45
Total	116,945		104,684		
Less accumulated depreciation and amortization	6,861		3,851		
Total net of accumulated depreciation and amortization	110,084		100,833		
Construction work in progress	130,310		26,106		
Net electric and gas	$ 240,394		$ 126,939		

2006

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	2006 Weighted Average Useful Life	Lives (in years)
Coal mining	$ 77,195	$ 41,725	$ 35,470	$ 5,263	$ 40,733	15	3-25
Oil and gas	486,596	120,789	365,807	—	365,807	24	3-25
Energy marketing	2,243	1,022	1,221	—	1,221	4	2-7
Power generation	736,796	154,559	582,237	687	582,924	29	3-40
	$ 1,302,830	$ 318,095	$ 984,735	$ 5,950	$ 990,685		

2005

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	2005 Weighted Average Useful Life	Lives (in years)
Coal mining	$ 73,817	$ 38,154	$ 35,663	$ 3,808	$ 39,471	16	3-39
Oil and gas	322,749	92,065	230,684	—	230,684	24	4-30
Energy marketing	1,497	692	805	—	805	4	3-39
Power generation	733,964	128,823	605,141	68	605,209	29	3-40
	$ 1,132,027	$ 259,734	$ 872,293	$ 3,876	$ 876,169		

2006

	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	2006 Weighted Average Useful Life	Lives (in years)
Corporate	$ 10,716	$ 5,826	$ 4,890	$ 10	$ 4,900	4	3-10

2005

	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	2005 Weighted Average Useful Life	Lives (in years)
Corporate	$ 8,494	$ 4,357	$ 4,137	$ 45	$ 4,182	4	3-10

(5) JOINTLY OWNED FACILITIES

The Company's subsidiary, Black Hills Power, owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. Black Hills Power 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, 2006, Black Hills Power's investment in the Plant included $76.3 million in electric plant and $41.0 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. Black Hills Power's share of direct expenses of the Plant was $7.9 million, $6.1 million and $6.0 million for the years ended December 31, 2006, 2005 and 2004, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 18, the Company's coal mining subsidiary, WRDC, 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 WRDC's 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. WRDC's sales to the Plant were $16.8 million, $18.1 million and $16.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Black Hills Power 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. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides the Company with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW – 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2006, 2005 and 2004, Black Hills Power's share of direct expenses was $0.1 million, $0.2 million and $0.1 million, respectively. As of December 31, 2006, Black Hills Power's investment in the transmission tie was $19.8 million, with $1.5 million of accumulated depreciation and is included in the corresponding captions in the accompanying Consolidated Balance Sheets.

The Company, through its subsidiary 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, 2006, 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, $3.1 million and $2.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. The Company's share of direct expenses for the Gas Plant was $0.3 million, $0.3 million and $0.3 million for the years ended December 31, 2006, 2005 and 2004, respectively. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

(6) LONG-TERM DEBT

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

	2006	2005
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes	(186)	(215)
	224,814	224,785
First mortgage bonds:		
Electric utility		
8.06% due 2010	30,000	30,000
9.49% due 2018	3,390	3,680
9.35% due 2021	24,975	26,640
7.23% due 2032	75,000	75,000
Electric and gas utility		
7.50% due 2024	7,200	7,400
Industrial development revenue bonds, variable rate, at 4.06% due 2021[c]	7,000	7,000
Industrial development revenue bonds, variable rate, at 4.06% due 2027[c]	10,000	10,000
Unamortized debt premium on 7.5% first mortgage bonds due 2024	1,600	1,694
	159,165	161,414
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
GECC Financing at 7.36% due 2010[a][d]	24,214	26,213
Other	3,553	4,464
	46,417	49,327
Project financing floating rate debt:		
Valmont and Arapahoe at 6.04% refinanced 2006[b]	—	118,174
Valmont and Arapahoe at 6.24% due 2013[b] [d]	86,786	—
Wygen I project at 4.84% refinanced 2006[c]	—	111,100
Wygen I project at 5.99% due 2008[c][d]	128,264	17,164
	215,050	246,438
Total long-term debt	645,446	681,964
Less current maturities	(17,106)	(11,771)
Net long-term debt	$ 628,340	$ 670,193

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

(b) In July 2006, the Company entered into a Second Amended and Restated Credit Agreement for the floating-rate project debt for the Valmont and Arapahoe plants. In conjunction with the refinancing, the Company made a payment in the amount of $21.3 million on the $111.3 million principal outstanding at June 30, 2006.

(c) In May 2006, the Company entered into an Amended and Restated Credit Agreement refinancing the Wygen I debt and extending the maturity date to June 2008.

(d) Interest rates are presented as of December 31, 2006.

At December 31, 2006, approximately 58 percent, or $150.0 million, of the Company's $259.1 million variable rate debt balance has been hedged with interest rate swaps converting floating rates to fixed rates with a weighted average LIBOR swap rate of 5.04 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 Wygen I project debt and a portion of the Valmont and Arapahoe project debt are additionally guaranteed by the Company (see Note 19).

Certain debt instruments of the Company and its subsidiaries contain restrictions and covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2006. Also, certain of the subsidiaries' debt agreements provide that approximately $3.1 million of the subsidiaries' cash balance at December 31, 2006 may not be distributed to the parent company.

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $17.1 million in 2007, $145.4 million in 2008, $17.1 million in 2009, $63.4 million in 2010, $15.2 million in 2011 and $385.8 million thereafter.

(7) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $400.0 million at December 31, 2006 and 2005. The $400.0 million line of credit outstanding at December 31, 2006 is a revolving credit facility, which terminates May 4, 2010. The Company had $145.5 million of borrowings and $49.4 million of letters of credit and $55.0 million of borrowings and $60.7 million of letters of credit issued on the lines at December 31, 2006 and 2005, respectively. The Company has no compensating balance requirements associated with these lines of credit.

The $400.0 million revolving bank facility is 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 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 the Company's credit ratings; at 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 6.02 percent one-month borrowing rate as of December 31, 2006).

In addition to the above lines of credit, at December 31, 2006, Enserco has a $260.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas and crude oil. The line of credit is secured by all of Enserco's assets and expires on May 11, 2007. At December 31, 2006 and 2005, there were outstanding letters of credit issued under the facility of $158.7 million and $165.1 million, respectively, with no borrowing balances on the facility.

The credit facility and notes payable contain certain restrictive covenants including, among others, the maintenance of an interest expense coverage ratio, a recourse leverage ratio and a total level of consolidated net worth. At December 31, 2006, the Company and its subsidiary were in compliance with the debt covenants. These facilities do not contain default provisions pertaining to credit rating status.

(8) ASSET RETIREMENT OBLIGATIONS

SFAS 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and 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 the Oil and gas segment, reclamation of coal mining sites at the Coal mining segment and removal of fuel tanks and transformers containing PCB's at the Electric and gas utility segment.

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

	Balance at 12/31/05	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/06
Oil and gas	$ 8,791	$ 4,468	$ (799)	$ 780	$ 13,240
Mining	15,985	479	(1,049)	590	16,005
Electric and gas utility	182	—	(29)	18	171
Total	$ 24,958	$ 4,947	$ (1,877)	$ 1,388	$ 29,416

	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

(9) 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 had 1,068,258 shares available to grant at December 31, 2006.

At December 31, 2006, the Company had one stock-based employee compensation plan under which it can grant stock options to its employees and three prior plans with stock options outstanding. Prior to January 1, 2006, the Company accounted for these plans under the recognition and measurement principles of APB 25 and related interpretations. Prior to 2006, no stock-based compensation expense related to stock options was reflected in net income as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. However, the Company did recognize stock-based compensation expense for other non-vested share awards including restricted stock and restricted stock units, performance shares and directors' phantom shares.

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 123 to stock-based employee compensation (in thousands, except per share amounts):

	2005	2004
Net income available for common stock, as reported	$ 33,261	$ 57,652
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(689)	(861)
Pro forma net income	$ 32,572	$ 56,791
Earnings per share:		
As reported –		
Basic		
Continuing operations	$ 1.00	$ 1.73
Discontinued operations	0.02	0.05
Total	$ 1.02	$ 1.78
Diluted		
Continuing operations	$ 0.98	$ 1.71
Discontinued operations	0.02	0.05
Total	$ 1.00	$ 1.76
Pro forma –		
Basic		
Continuing operations	$ 0.97	$ 1.70
Discontinued operations	0.02	0.05
Total	$ 0.99	$ 1.75
Diluted		
Continuing operations	$ 0.96	$ 1.68
Discontinued operations	0.02	0.05
Total	$ 0.98	$ 1.73

On January 1, 2006 the Company adopted the fair value recognition provisions of SFAS 123(R) requiring the recognition of expense related to the fair value of stock-based compensation awards. The Company elected the modified prospective transition method. Under this method, compensation expense is recognized for all stock-based awards granted prior to, but not yet vested as of January 1, 2006 and all stock-based awards granted subsequent to January 1, 2006. Adoption of SFAS 123(R) did not have a material effect on the Company's consolidated financial position, results of operations or cash flows. Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of SFAS 123(R) and is recognized over the vesting periods of the individual plans. Total stock-based compensation expense for the years ended December 31, 2006, 2005 and 2004 was $2.6 million ($1.7 million, after-tax), $3.2 million ($2.1 million, after-tax) and $2.4 million ($1.6 million, after-tax) respectively, and is included in Administrative and general expense on the accompanying Consolidated Statements of Income. In accordance with the modified prospective transition method of SFAS 123(R), financial results for prior periods have not been restated. As of December 31, 2006, total unrecognized compensation expense related to stock options and other non-vested stock awards is $3.5 million and is expected to be recognized over a weighted-average period of 1.8 years.

In November 2005, the FASB issued FSP 123(R)-3. FSP 123(R)-3 provides an alternative method of calculating the excess tax benefits available to absorb tax deficiencies recognized subsequent to the adoption of SFAS 123(R). The calculation of excess tax benefits reported as an operating cash outflow and a financing inflow in the Consolidated Statements of Cash Flows required by FSP No. 123(R)-3 differs from that required by SFAS 123(R). The Company has decided not to adopt the transition method described in FSP No. 123(R)-3.

Stock Options

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 ten years after the grant date.

A summary of the status of the stock option plans at December 31, 2006 is as follows:

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		(in years)	(in thousands)
Balance at January 1, 2006	854	$ 29.56		
Granted	15	33.17		
Forfeited/cancelled	(18)	33.53		
Expired	—	—		
Exercised	(126)	29.12		
Balance at December 31, 2006	725	$ 29.61	5.2	$ 5,311
Exercisable at December 31, 2006	655	$ 29.50	4.9	$ 4,871

The weighted-average grant-date fair value of options granted during the years ended December 31, 2006, 2005 and 2004 was $3.79, $6.93 and $6.90, respectively. The total intrinsic value of options (the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option) exercised during the years ended December 31, 2006, 2005 and 2004 was $0.8 million, $5.2 million and $0.7 million, respectively. The total fair value of shares vested during the years ended December 31, 2006, 2005 and 2004 was $0.6 million, $1.0 million and $1.2 million, respectively.

The fair value of share-based awards is estimated on the date of grant using the Black-Scholes option pricing model. The fair value is affected by the Company's stock price as well as a number of assumptions. The assumptions used to estimate the fair value of share-based awards are as follows:

Valuations Assumptions[1]	2006	2005	2004
Weighted average risk-free interest rate[2]	4.94%	3.90%	3.82%
Weighted average expected price volatility[3]	21.54%	42.27%	43.52%
Weighted average expected dividend yield[4]	3.98%	4.17%	4.16%
Expected life in years[5]	7	7	7

[1] Forfeitures are estimated using historical experience and employee turnover.
[2] Based on treasury interest rates with terms consistent with the expected life of the options.
[3] Based on a blended historical and implied volatility of the Company's stock price in 2006 and historical volatility only in 2005 and 2004.
[4] Based on the Company's historical dividend payout and expectation of future dividend payouts and may be subject to substantial change in the future.
[5] Based upon historical experience.

Net cash received from the exercise of options for the years ended December 31, 2006, 2005 and 2004 was $3.7 million, $10.2 million and $1.6 million, respectively. The tax benefit realized from the exercise of shares granted for the years ended December 31, 2006, 2005 and 2004 was $0.3 million, $1.8 million and $0.2 million, respectively, and was recorded as an increase to equity.

As of December 31, 2006, there was $0.2 million of unrecognized compensation expense related to stock options that is expected to be recognized over a weighted-average period of 0.8 years.

Restricted Stock and Restricted Stock Units

The fair value of restricted stock and restricted stock unit awards equals the market price of the Company's stock on the date of grant.

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.

A summary of the status of the restricted stock and non-vested restricted stock units at December 31, 2006 is as follows:

	Stock And Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Balance at January 1, 2006	90	$ 30.71
Granted	63	35.57
Vested	(41)	30.12
Forfeited	(7)	32.26
Balance at December 31, 2006	105	$ 33.76

The weighted-average grant-date fair value of restricted stock and restricted stock units granted in the years ended December 31, 2006, 2005 and 2004 was $35.57, $31.64 and $29.10, per share, respectively. The total fair value of shares vested during the years ended December 31, 2006, 2005 and 2004 was $1.3 million, $1.2 million and $1.2 million, respectively.

As of December 31, 2006, there was $2.2 million of unrecognized compensation expense related to non-vested restricted stock and non-vested restricted stock units that is expected to be recognized over a weighted-average period of 2.1 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based 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.

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.

Outstanding Performance Periods at December 31, 2006 are as follows:

Grant Date	Performance Period	Target Grant of Shares (in thousands)
March 1, 2004	March 1, 2004 – December 31, 2006	21
January 1, 2005	January 1, 2005 – December 31, 2007	37
January 1, 2006	January 1, 2006 – December 31, 2008	32

The performance awards are paid 50 percent in cash and 50 percent in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control performance awards are paid 100 percent in cash. If it is ever determined that a change-in-control is probable, the equity portion of $0.6 million at December 31, 2006 will be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31, 2006 and changes during the twelve-month period ended December 31, 2006, is as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average December 31, 2006 Fair Value
Balance at January 1, 2006	38	$ 29.95	38	
Granted	17	32.06	17	
Forfeited	(4)	30.54	(4)	
Vested	(6)	29.92	(6)	
Balance at December 31, 2006	45	$ 32.60	45	$ 32.79

The weighted-average grant-date fair value of performance share awards granted in the years ended December 31, 2006, 2005 and 2004 was $32.06, $29.97 and $29.92, per share, respectively. The grant date fair value for the performance shares granted in 2006 was determined by Monte Carlo simulation using a blended volatility of 21 percent comprised of 50 percent historical volatility and 50 percent implied volatility and the average risk-free interest rate of the three-year U.S. Treasury security rate in effect as of the grant date. The grant date fair value for the performance shares issued in 2005 and 2004 was equal to the market value of the common stock on the grant date.

During the twelve months ended December 31, 2006, the Company issued 11,667 shares of common stock and paid $0.4 million for the Performance Period of March 1, 2004 to December 31, 2005, for a total intrinsic value of $0.8 million. The payout was fully accrued at December 31, 2005.

On February 1, 2007, the Compensation Committee of the Board of Directors determined that the Company's total shareholder return for the March 1, 2004 to December 31, 2006 performance period was at the 37^{th} percentile of its peer group and approved a payout equal to 37 percent of target shares. This payout was fully accrued at December 31, 2006.

As of December 31, 2006, there was $1.0 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

Other Plans

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. At December 31, 2006, 91,940 shares of unissued common stock were available for future offering under the Plan.

The Company issued 36,685 shares of common stock with an intrinsic value of $910,000 in the twelve months ended December 31, 2006 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2005. The Company issued 3,266 and 10,310 shares of common stock in 2005 and 2004, respectively under the Short-term Annual Incentive Plan.

In addition, the Company will issue common stock with an intrinsic value of $1.2 million in 2007 for the 2006 Short-term Annual Incentive Plan. The payout was fully accrued at December 31, 2006.

Prior to 2005, the Company maintained an 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 shares of common stock under the ESPP in 2004.

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: interest expense 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 aggregate consolidated net income since January 1, 2005. As of December 31, 2006, the Company was in compliance with the above covenants.

Treasury Shares Acquired

The Company acquired 6,224, 2,771 and 4,005 shares of treasury stock related to forfeitures of unvested restricted stock in 2006, 2005 and 2004, respectively, and 8,095, 16,872 and 7,508 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 2006, 2005 and 2004, 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.

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 36,939	$ 36,939	$ 31,817	$ 31,817
Restricted cash	$ 2,004	$ 2,004	$ —	$ —
Derivative financial instruments – assets	$ 72,115	$ 72,115	$ 22,579	$ 22,579
Derivative financial instruments – liabilities	$ 25,571	$ 25,571	$ 28,764	$ 28,764
Notes payable	$ 145,500	$ 145,500	$ 55,000	$ 55,000
Long-term debt, including current maturities	$ 645,446	$ 663,162	$ 681,964	$ 709,459

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.

(11) IMPAIRMENT OF LONG-LIVED ASSETS, GOODWILL 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 became uneconomic. Accordingly, the Company assessed the recoverability of the carrying value of Las Vegas I in accordance with the provisions of SFAS 144.

Las Vegas I is a 53 MW, natural gas-fired, combined-cycle turbine operating under a contract as a QF as defined by PURPA. Under the contract, which extends through 2024, the Company sells capacity and energy to NPC. 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 recorded an impairment charge for 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.

(12) 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. Daksoft primarily provides information technology support to the Company, and its results are included in "Corporate" for segment reporting.

(13) OPERATING LEASES

The Company has entered into lease agreements relating to certain power plant land leases, oil and gas drilling rigs, office facility leases and storage agreements. Rental expense incurred under these operating leases was $1.5 million, $0.9 million and $0.8 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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

2007	$ 1,658
2008	1,621
2009	1,414
2010	718
2011	747
Thereafter	9,933
	$ 16,091

(14) INCOME TAXES

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

	2006	2005	2004
		(in thousands)	
Current:			
Federal	$ 155	$ 24,601	$ 748
State	(479)	620	(2,771)
Foreign	893	605	448
	569	25,826	(1,575)
Deferred:			
Federal	32,305	(8,743)	29,075
State	1,222	276	(1,122)
Tax credit amortization	(294)	(315)	(279)
	33,233	(8,782)	27,674
	$ 33,802	$ 17,044	$ 26,099

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,	2006	2005
	(in thousands)	
Deferred tax assets, current:		
Asset valuation reserves	$ 1,474	$ 1,644
Mining development and oil exploration	333	633
Unbilled revenue	1,694	1,659
Deferred costs	3,066	—
Employee benefits	1,883	2,242
Items of other comprehensive income	26	2,066
Derivative fair value adjustments	216	—
Other	30	299
	8,722	8,543
Deferred tax liabilities, current:		
Prepaid expenses	1,257	2,347
Derivative fair value adjustments	15	1,650
Employee benefits	—	272
Items of other comprehensive income	5,238	73
Other	3,427	5,657
	9,937	9,999
Net deferred tax liability, current	$ 1,215	$ 1,456
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 2,534	$ 3,959
Mining development and oil exploration	55	262
Employee benefits	17,241	10,830
Regulatory asset	1,532	1,717
Deferred revenue	621	677
Deferred costs	700	917
State net operating loss	342	556
Items of other comprehensive income	4,967	1,709
Foreign tax credit carryover	1,530	1,345
Net operating loss (net of valuation allowance)	12,956	15,871
Asset impairment	57,659	57,659
Derivative fair value adjustment	183	119
Other	4,052	6,959
	104,372	102,580
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	185,237	163,464
Employee benefits	6,969	3,151
Regulatory liability	4,049	3,984
Mining development and oil exploration	72,249	55,264
Deferred costs	2,371	5,030
Derivative fair value adjustments	—	21
Items of other comprehensive income	968	53
Other	6,861	6,146
	278,704	237,113
Net deferred tax liability, non-current	$ 174,332	$ 134,533
Net deferred tax liability	$ 175,547	$ 135,989

The following table reconciles the change in the net deferred income tax liability from December 31, 2005 to December 31, 2006 to deferred income tax expense:

	2006 (in thousands)
Net change in deferred income tax liability from the preceding table	$ 39,558
Deferred taxes related to change in accounting method	1,093
Deferred taxes associated with other comprehensive loss	(5,616)
Deferred taxes related to net operating loss acquisitions	(460)
Deferred taxes related to regulatory assets and liabilities	(855)
Other	(487)
Deferred income tax expense for the period	$ 33,233

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

	2006	2005	2004
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	0.4	1.2	(3.3)
Amortization of excess deferred and investment tax credits	(0.5)	(0.8)	(0.5)
Percentage depletion in excess of cost	(1.2)	(2.0)	(0.8)
Equity AFUDC	(0.9)	(0.3)	—
Goodwill impairment	—	1.2	—
IRS exam tax adjustment*	(2.4)	—	—
Other	0.9	(0.1)	1.4
	31.3%	34.2%	31.8%

*As a result of the settlement of an Internal Revenue Service (IRS) exam of the tax years 2001-2003 with respect to certain tax positions taken by the Company, a reduction to income tax expense of approximately $2.6 million was recorded during 2006.

At December 31, 2006, the Company had the following remaining net operating loss (NOL) carryforwards which were acquired as part of the Mallon and Pepperell acquisitions (in thousands):

Net Operating Loss Carryforward	Expiration Year
$ 481	2012
512	2018
374	2019
2,501	2020
2,852	2021
6,001	2022
1,086	2023

As of December 31, 2006, the Company had a valuation allowance of $0.9 million against these NOL carryforwards. Ultimate usage of these NOL's depends upon the Company's future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOL's, the offsetting amount would affect 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, 2006, the Company had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year
$ 9	2009
254	2010
696	2011
345	2012
26	2013
31	2014
121	2015
47	2016

(15) 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):

	2006		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 994	$ (348)	$ 646
Fair value adjustment of derivatives designated as cash flow hedges	28,640	(10,419)	18,221
Reclassification adjustments of cash flow hedges settled and included in net income	(5,289)	1,851	(3,438)
Other comprehensive income (loss)	$ 24,345	$ (8,916)	$ 15,429

	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

(16) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of SFAS 144. Accordingly, results of operations and the related charges for discontinued operations have been classified as “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 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 was used for debt reduction or other corporate purposes. For business segment reporting purposes, BHER’s results were previously included in the Energy marketing and transportation segment.

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

	2006	2005	2004
Operating revenues	$ 171,911	$ 778,103	$ 636,572
Pre-tax (loss) income from discontinued operations (including 2006 severance payments)	$ (3,018)	$ 4,223	$ 7,641
Pre-tax gain on sale of assets	13,659	—	—
Income tax expense	(3,832)	(1,255)	(2,732)
Net income from discontinued operations	$ 6,809	$ 2,968	$ 4,909

	2006	2005
Current assets	$ 1,424	$ 94,697
Property, plant and equipment	—	25,364
Other non-current assets	—	2,097
Current liabilities	(2,352)	(89,750)
Other non-current liabilities	(174)	(3,068)
Net (deficit) assets	$ (1,102)	$ 29,340

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.

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

	2006	2005	2004
Revenues	$ —	$ 21,877	$ 39,586
Pre-tax income (loss) from discontinued operations	$ —	$ 3,978	$ (6,068)
Pre-tax loss on disposal	—	(7,490)	—
Income tax benefit	164	1,405	2,127
Net income (loss) from discontinued operations	$ 164	$ (2,107)	$ (3,941)

Sale of Pepperell Plant

On April 8, 2005, the Company sold the 40 MW gas-fired Pepperell plant to an unrelated party for a nominal amount plus the assumption of certain obligations. For business segment reporting purposes, the Pepperell plant results were previously included in the Power generation segment.

Revenues and net loss from the discontinued operations during the years ended December 31, are as follows (in thousands):

	2005	2004
Operating revenues	$ —	$ 120
Pre-tax loss from discontinued operations	(326)	(972)
Pre-tax loss on disposal	(39)	(1,064)
Income tax benefit	132	712
Net loss from discontinued operations	$ (233)	$ (1,324)

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

(17) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

The Company sponsors two 401(k) savings plans. The Black Hills Corporation Plan is for eligible employees of the Company and its subsidiaries, but excluding the employees of Cheyenne Light. The Cheyenne Light 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 an employee's 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 Plan matching contributions were $1.5 million for 2006, $1.5 million for 2005 and $1.4 million for 2004. The Cheyenne Light Retirement Savings Plan matching contributions were $0.2 million for 2006 and $0.2 million for the initial plan year of 2005. The Cheyenne Light Plan profit sharing contributions were $0.1 million for 2006 and $0.2 million for the initial plan year of 2005.

SFAS 158

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

Prior to the December 31, 2006 effective date of SFAS 158, liabilities recorded for postretirement benefit plans were reduced by any unrecognized net periodic benefit cost. Upon adoption of SFAS 158, the unrecognized net periodic benefit cost, previously recorded as an offset to the liability for benefit obligations, was reclassified within accumulated other comprehensive income (loss), net of tax. For the Company's regulated utilities, the Company applied the guidance under SFAS 71, and accordingly, the unrecognized net periodic benefit cost that would have been reclassified to accumulated other comprehensive income was alternatively recorded as a regulatory asset or regulatory liability, net of tax.

The following table discloses the incremental effect of applying SFAS 158 on individual line items in the Company's 2006 Consolidated Balance Sheet (in thousands):

	Before Application of SFAS 158	Impact from Adoption of SFAS 158	Impact of SFAS 71 Adjustment	After Application of SFAS 158
Other assets – other	$ 36,628	$ (5,308)	$ 10,817	$ 42,137
Accrued liabilities	$ 94,020	$ 1,000	$ —	$ 95,020
Deferred income taxes	$ 177,632	$ (6,877)	$ 3,577	$ 174,332
Deferred credits and other liabilities – other	$ 102,374	$ 13,325	$ 598	$ 116,297
AOCI	$ 5,599	$ (12,756)	$ 6,642	$ (515)

Defined Benefit Pension Plan

The Company has two noncontributory defined benefit pension plans (the Pension Plans). The BHC Pension Plan covers the employees of the Company and the employees of the subsidiaries Black Hills Service Company, Black Hills Power, WRDC and BHEP 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 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 Pension Plans' assets are held in trust and consist primarily of equity and fixed income investments. The Company uses a September 30 measurement date for the Pension Plans.

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

The expected long-term rate of return for equity investments was 9.5 percent for both the 2006 and 2005 plan years. For determining the expected long-term rate of return for equity assets, the Company reviewed interest rate trends and annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2006, 11.8 percent, 12.4 percent, 11.0 percent and 10.6 percent, respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on 10-year treasury bonds of 7.1 percent from 1962 to 2006, 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 assets for the Company's Pension Plans at September 30:

	2006	2005
Domestic equity	50.3%	52.9%
Foreign equity	25.3	40.6
Fixed income	15.6	3.4
Cash	8.8	3.1
Total	100.0%	100.0%

The Pension Plans' current investment policy includes a target asset allocation as follows:

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

The Pension Plans' investment policy includes the investment objective that the achieved long-term rate of return meets or exceeds the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy provides that the Pension Plans 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 and fixed income through actively managed mutual funds.

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

Cash Flows

The Company made no contributions to the BHC Pension Plan in 2006 and expects to make no contributions to the Plan in the 2007 fiscal year.

The Company made a $1.2 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2006 and expects to make a $0.5 million contribution during the 2007 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.

Plan Assets

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

Estimated Cash Flows

The estimated employer contribution is expected to be $0.7 million in 2007. 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 2006 fiscal year was an actuarial gain of approximately $1.9 million. The effect on 2007 net periodic postretirement benefit cost was a decrease of approximately $0.2 million.

Plan Assets

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

Estimated Cash Flows

The estimated employer contribution is expected to be $0.3 million in 2007. 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 2006 and 2005, a statement of funded status for 2005, components of the net periodic expense for the years ended 2006, 2005 and 2004 and elements of accumulated other comprehensive income for 2006.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2006	2005	2006	2005	2006	2005
	(in thousands)		(in thousands)		(in thousands)	
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 73,855	$ 64,760	$ 19,206	$ 16,980	$ 14,275	$ 10,992
Projected benefit obligation of Cheyenne Light at acquisition	—	2,407	—	—	—	3,932
Service cost	2,596	2,214	349	344	654	705
Interest cost	4,165	3,940	1,079	1,009	813	874
Actuarial (gain) loss	(511)	(411)	11	1,257	(1,198)	(2,108)
Amendments	—	—	—	—	(300)	—
Discount rate change	—	2,661	—	—	—	—
Change in assumptions	—	729	—	—	—	—
Benefits paid	(2,634)	(2,445)	(802)	(384)	(669)	(569)
Plan participant's contributions	—	—	—	—	467	449
Net increase (decrease)	3,616	9,095	637	2,226	(233)	3,283
Projected benefit obligation at end of year	$ 77,471	$ 73,855	$ 19,843	$ 19,206	$ 14,042	$ 14,275

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2006	2005	2006	2005	2006	2005
			(in thousands)			
Beginning market value of plan assets	$ 59,285	$ 52,782	$ —	$ —	$ —	$ —
Investment income	8,189	8,948	—	—	—	—
Contributions	1,150	—	—	—	—	—
Benefits paid	(2,634)	(2,445)	—	—	—	—
Ending market value of plan assets	$ 65,990	$ 59,285	$ —	$ —	$ —	$ —

Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
	2006	2006	2006
		(in thousands)	
Regulatory asset	$ 10,676	$ —	$ 141
Current liability	$ —	$ 742	$ 258
Non-current liability	$ 11,481	$ 18,920	$ 13,644
Regulatory liability	$ —	$ —	$ 598

Funded Status

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
	2005	2005 (in thousands)	2005
Funded status	$ (14,570)	$ (19,206)	$ (14,275)
Unrecognized net loss	18,150	9,877	330
Unrecognized prior service cost	1,162	43	(264)
Unrecognized transition obligation	—	—	1,049
Contributions	—	255	48
Net amount recognized	$ 4,742	$ (9,031)	$ (13,112)

Amounts recognized in statement of financial position consist of:

	Defined Benefit Pension Plans (a)	Supplemental Nonqualified Defined Benefit Retirement Plans (b)	Non-pension Defined Benefit Postretirement Plans
	2005	2005 (in thousands)	2005
Amounts recognized in consolidated balance sheets consist of:			
Net asset (liability)	$ 4,742	$ (13,844)	$ (13,112)
Intangible asset	—	42	—
Contributions	—	255	—
Accumulated other comprehensive loss	—	4,516	—
Net amount recognized	$ 4,742	$ (9,031)	$ (13,112)

(a) The provisions of SFAS 87 required the Company to record a net pension asset of $4.7 million at December 31, 2005. This amount is included in Other assets, Other on the accompanying Consolidated Balance Sheet.

(b) The provisions of SFAS 87 required the Company to record a net pension liability of $13.8 million at December 31, 2005. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheet.

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2006	2005	2006	2005	2006	2005
			(in thousands)			
Accumulated benefit obligation - BHC	$ 60,214	$ 57,254	$ 14,274	$ 13,844	$ 9,922	$ 10,195
Accumulated benefit obligation – Cheyenne Light	$ 1,754	$ 1,328	$ —	$ —	$ 4,120	$ 4,080

Components of Net Periodic Expense

	Defined Benefit Pension Plans 2006	Defined Benefit Pension Plans 2005	Defined Benefit Pension Plans 2004	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2005	Supplemental Nonqualified Defined Benefit Retirement Plans 2004	Non-pension Defined Benefit Postretirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2005	Non-pension Defined Benefit Postretirement Plans 2004
	(in thousands)								
Service cost	$ 2,596	$ 2,214	$ 1,772	$ 349	$ 344	$ 536	$ 654	$ 705	$ 561
Interest cost	4,165	3,940	3,637	1,079	1,009	965	813	874	662
Expected return on assets	(4,988)	(4,628)	(4,515)	—	—	—	—	—	—
Amortization of prior service cost	153	215	232	13	9	9	(24)	(24)	(24)
Amortization of transition obligation	—	—	—	—	—	—	150	150	150
Recognized net actuarial loss	906	1,183	1,498	797	629	748	—	100	189
Net periodic expense	$ 2,832	$ 2,924	$ 2,624	$ 2,238	$ 1,991	$ 2,258	$ 1,593	$ 1,805	$ 1,538

Accumulated Other Comprehensive Income

In accordance with SFAS 158, amounts included in accumulated other comprehensive income (loss), after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31, 2006 are as follows:

	Defined Benefit Pension Plans 2006	Supplemental Nonqualified Defined Benefit Retirement Plans 2006	Non-pension Defined Benefit Postretirement Plans 2006
		(in thousands)	
Net (loss) gain	$ (2,281)	$ (5,909)	$ 65
Prior service cost	(224)	(20)	—
Transition obligation	—	—	(34)
	$ (2,505)	$ (5,929)	$ 31

The amounts in accumulated other comprehensive income, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2007 are as follows:

	Defined Benefits Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
		(in thousands)	
Net loss (gain)	$ 330	$ 463	$ (10)
Prior service cost	99	8	—
Transition obligation	—	—	39
Total net periodic benefit cost expected to be recognized during calendar year 2007	$ 429	$ 471	$ 29

Additional Information

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

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:	2006	2005	2004	2006	2005	2004	2006	2005	2004
Discount rate	5.95%	5.75%	6.00%	5.95%	5.75%	6.00%	5.95%	5.75%	6.00%
Rate of increase in compensation levels	4.31%	4.34%	4.39%	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:	2006	2005	2004	2006	2005	2004	2006	2005	2004
Discount rate	5.75%	6.00%	6.00%	5.75%	6.00%	6.00%	5.75%	6.00%	6.00%
Expected long-term rate of return on assets*	8.50%	9.00%	9.50%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.34%	4.39%	5.00%	5.00%	5.00%	5.00%	N/A	N/A	N/A

*The expected rate of return on plan assets remained at 8.5 percent for the calculation of the 2007 net periodic pension cost.

The healthcare trend rate assumption for 2006 fiscal year benefit obligation determination and 2007 fiscal year expense is a 10 percent increase for 2006 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011. The healthcare cost trend rate assumption for the 2005 fiscal year benefit obligation determination and 2006 fiscal year expense was an 11 percent increase 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 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 25 percent and the accumulated periodic postretirement benefit obligation $2.8 million or 20 percent. A 1 percent decrease would reduce the service and interest cost by $0.3 million or 19 percent and the accumulated periodic postretirement benefit obligation $2.2 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
2007	$ 2,892	$ 741	$ 288	$ (29)	$ 259
2008	3,096	767	347	(32)	315
2009	3,248	763	420	(36)	384
2010	3,486	794	524	(39)	485
2011	3,717	814	601	(44)	557
2012-2016	22,822	5,034	3,987	(320)	3,667

(18) 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 includes the VIE in the accompanying consolidated financial statements. 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 VIE, 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 VIE of the shortfall up to 83.5 percent of the adjusted acquisition cost, or approximately $111.0 million. The Company has guaranteed the obligations of Black Hills Wyoming to the variable interest entity.

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 MW of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduced the contract capacity by 25 MW (5 MW per year starting in 2000) to the current 50 MW contract capacity. 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 2006, $10.1 million in 2005 and $10.0 million in 2004.

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

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 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 MW, 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 MW 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.

- The Company has a ten-year contract with Cheyenne Light for 60 MW of contingent capacity from the 90 MW Wygen I plant, which expires March 2013. As with the Gillette CT contract, this agreement has been temporarily assigned to PSCo through December 31, 2007.

- The Company has a ten-year power sales contract with MEAN for 20 MW 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 MW of the output of the 53 MW Las Vegas I plant with NPC through 2024. Under the terms of the contract, the Company assumes the fuel price risk associated with the energy generation.

- 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 MW. 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 SCE 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 had a contract with MDU, which expired January 1, 2007, for the sale of up to 55 MW of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company entered into a new power purchase agreement with MDU for the supply of up to 74 MW of capacity and energy for Sheridan, Wyoming from 2007 through 2016, which is subject to regulatory approval by the WPSC. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 MW of capacity and energy. The agreement renews automatically and requires a seven-year notice of termination. Both contracts are served by 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 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, 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 II, 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, WRDC 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, $0.6 million and $0.7 million was charged to accretion expense for the years ended December 31, 2006, 2005 and 2004, respectively. Approximately $0.5 million, $0.4 million and $0.5 million was charged to depreciation expense for the years ended December 31, 2006, 2005 and 2004, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $16.0 million at December 31, 2006 and 2005.

Legal Proceedings

Forest Fire Claims

The Company's subsidiary, Black Hills Power, settled governmental claims related to the Grizzly Gulch Fire and the Hell Canyon Fire. On August 25, 2006, the U. S. District Court approved a full and final settlement of all governmental claims relating to both fires. The settlement agreements provided for the release and dismissal of all claims against Black Hills Power. For its part, Black Hills Power did not admit liability for the fires, but agreed to make settlement payments for the Grizzly Gulch and Hell Canyon fires. The settlements did not have a material adverse effect on the Company's financial condition or results of operations.

While the government case was pending, a number of private claims for damages arising out of the Grizzly Gulch Fire were filed in Lawrence County Circuit Court, South Dakota. Counsel for these litigants had agreed to a stay of the proceedings pending the resolution of governmental claims. As a result of the settlement of the governmental cases, the private claims will now proceed through discovery. No trial date or other scheduling order has been set for these matters. The Company will continue to defend these matters. While the outcome of the remaining private suits is uncertain, they are not expected to have a material impact upon the Company's financial condition or results of operations.

PPM Energy, Inc. Demand for Arbitration

The Company's subsidiary, Black Hills Power received a Demand for Arbitration from PPM on January 2, 2004, that alleged claims for breach of contract and requested a declaration of the parties' rights and responsibilities under an Exchange Agreement executed in April of 2001. PPM asserted the Exchange Agreement obligated Black Hills Power to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM requested an award of damages in an amount not less than $20.0 million. Black Hills Power filed its Response to Demand, including a counterclaim that sought recovery of sums PPM had refused to pay pursuant to the Exchange Agreement. The dispute was presented to the arbitrator in August 2005 and the arbitrator delivered his decision on June 5, 2006.

The arbitrator concluded both parties failed to perform the Exchange Agreement, in certain respects. Black Hills Power paid PPM a net settlement of $1.1 million in accordance with the decision, but prevailed on other substantial claims for payment and performance. The Company does not believe that the decision will have a material impact on its ability to market surplus power in the future.

Acquisition Earn-Out Agreement Lawsuit

On August 13, 2004, Gerald R. Forsythe and other individuals identified as "Stockholders" under an Agreement and Plan of Merger dated July 7, 2000, commenced litigation against Black Hills Corporation in United States District Court, Northeastern District of Illinois, Eastern Division (the "Litigation"). The Litigation concerns the Company's performance of its obligations under the "Earn-Out" provisions of the Agreement and Plan of Merger. Under these provisions, the Stockholders, who are former owners of Indeck, were entitled to receive "contingent merger consideration" for a period of four years following the merger of the Company's wholly-owned subsidiary, Indeck Capital with BHEC. The "contingent merger consideration" was not to exceed $35.0 million and was based on the acquired companies' earnings over the four year period beginning in 2000. As of December 31, 2006, $11.3 million has been either paid or offered for payment under the "Earn-Out" provisions.

The Stockholders allege 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 contends that it has fully and in good faith performed all of its obligations under the Agreement and Plan of Merger.

In addition, the Company contended 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 Company filed a Motion to Dismiss or Stay the Litigation, along with an order compelling the Stockholders to pursue their claims in arbitration. On July 7, 2005, the U. S. District Court entered its order compelling arbitration of two issues relating to the Earn-Out calculation, but held that two other issues (inter-company interest allocations and capitalization of BHEC) would remain subject to determination through the Litigation. The court declined to stay the Litigation on those two issues and consequently, this dispute will be resolved in parallel proceedings. No trial date has been set.

On October 6, 2006, the Court granted Plaintiff's Motion to Amend the Complaint in the Litigation to add new claims, and re-characterize others. Under the Amended Complaint, a count for breach of contract was withdrawn and replaced by similar allegations under a theory of breach of the covenant of good faith and fair dealing. The first new count seeks damages for alleged destruction or "spoliation" of corporate records relating to the Earn-Out process and obligation. The second claim asserts damages for alleged fraud, and seeks recovery against current and former officers of the Company, as well as the Company itself. The fraud theory alleges that debt represented by inter-company loan transactions was "non-existent" or illegal, and representations by the Company to the contrary were fraudulent. Under the fraud claim, the Plaintiffs assert a similar claim for compensatory damages and add a new claim for exemplary damages. The Company hired separate counsel for the individual defendants and filed a motion to dismiss the Amended Complaint. A decision from the court is pending.

The parties retained an arbitrator who will direct the process and decide the issues in arbitration, according to the procedure stated in the Merger Agreement. No time schedule for completing the arbitration has been established.

The outcome of this matter is uncertain, as is the amount of contingent merger consideration that could be awarded following arbitration and/or litigation. If any additional merger consideration is awarded, it would be recorded as additional goodwill. If an adverse outcome occurred and punitive damages were awarded, the punitive damages would be recorded as an expense.

California Price Reporting and Anti-Trust Litigation

On August 17, 2006, the Company's subsidiary, Enserco, was served as an additional defendant in sixteen lawsuits pending in San Diego Superior Court, in the State of California, JCCP Nos. 4221, 4224, 4226, and 4228. The Plaintiffs are purported natural gas customers who initially filed separate lawsuits in various California superior courts. These lawsuits have been coordinated in the San Diego Superior court with numerous other natural gas actions under the heading, "In re Natural Gas Anti-Trust Cases I, II, III, IV and V." The lawsuits have been pending against other marketers, traders, transporters and sellers of natural gas since as early as 2004. Plaintiffs allege that beginning at least by the summer of 2000, defendants, including Enserco, used various practices to manipulate natural gas prices in California in violation of the Cartwright Act and other California state laws. The Plaintiffs assert certain wrongful conduct on the part of other defendants which is not asserted against Enserco. They allege manipulation of prices by Enserco through reporting of transactions to industry trade publications. No specific amount of damages is alleged. The trial court granted Enserco's Motion to Dismiss the complaints based upon the statute of limitations, and other defenses. The court allowed Plaintiffs to file an Amended Complaint against Enserco, which they did on February 5, 2007. Enserco will evaluate whether the Amended Complaint alleges facts which overcome previous procedural defects and will otherwise vigorously defend the lawsuits. While the Company cannot predict the final timing or outcome of these actions, they are not expected to have a material impact on the Company's consolidated financial position or results of operations.

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.

(19) 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 FIN 45, the Company records a liability for the fair value of the obligation it has undertaken for guarantees issued after December 31, 2002. Of the $189.6 million, $165.2 million was related to guarantees associated with subsidiaries' debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets.

As of December 31, 2006, the Company had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2006	Year Expiring
Guarantee payments under the Las Vegas I Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee payments of Black Hills Power under various transactions with Idaho Power Company	250	2007
Guarantee of payments of Cheyenne Light under various transactions with Tenaska Marketing Ventures	2,000	2007
Guarantee of payments of Cheyenne Light under various transactions with Questar Energy Trading Company	3,000	2007
Guarantee obligations under the Wygen I Plant Lease	111,018	2008
Guarantee payment and performance under credit agreements for two combustion turbines	24,214	2010
Guarantee payments of Las Vegas II to NPC under a power purchase agreement	5,000	2013
Guarantee of Black Hills Colorado project debt for Valmont and Arapahoe plants	30,000	2013
Indemnification for subsidiary reclamation/surety bonds	4,115	Ongoing
	$ 189,597	

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 $0.3 million of the obligations of its electric utility subsidiary, Black Hills Power, 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. The guarantee expires March 1, 2007.

The Company has guaranteed up to $2.0 million of the obligations of its electric and gas utility subsidiary, Cheyenne Light, under various transactions with Tenaska Marketing Ventures. To the extent liabilities exist under these transactions, such liabilities are subject to this guarantee and are included in the Consolidated Balance Sheets. The guarantee expires on March 31, 2007.

The Company has guaranteed up to $3.0 million of the obligations of its electric and gas utility subsidiary, Cheyenne Light, under various transactions with Questar Energy Trading Company. To the extent liabilities exist under these transactions, such liabilities are subject to this guarantee and are included in the Consolidated Balance Sheets. The guarantee expires on March 31, 2007.

On May 24, 2006, the Company entered into an Amended and Restated Credit Agreement for the project financing floating rate debt for Wygen I. In conjunction with the Amended and Restated Credit Agreement, the Company entered into an Amended and Restated Guarantee in favor of Wygen Funding, Limited Partnership, which continues the Company's guarantee obligations of Black Hills Wyoming under the Agreement for Lease and Lease for the Wygen I plant. The Company consolidates the VIE 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, 2006, 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 $20.8 million of debt of Black Hills Wyoming and $3.4 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 II under the Western Systems Power Pool Confirmation Agreement with NPC. 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.

On July 12, 2006, the Company's subsidiary, Black Hills Colorado, LLC, entered into a Second Amended and Restated Credit Agreement to refinance the floating-rate project debt for the Valmont and Arapahoe plants in the amount of $90.0 million. The maturity date of the amortizing borrowings is July 2013. In conjunction with the refinancing, the Company has guaranteed during the term of the debt the payment obligations of Black Hills Colorado, LLC, to the Bank of Nova Scotia, as administrative agent under the Credit Agreement, in an amount up to $30.0 million.

In addition, at December 31, 2006, the Company had guarantees in place totaling approximately $4.1 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.

(20) 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, 2006, 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: 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; and Wholesale Energy consisting of: Oil and gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region, Texas, California and other states; Power generation, which produces and sells power and capacity to wholesale customers primarily in the western United States; Coal mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and Energy marketing, which markets natural gas, crude oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regional markets.

On March 1, 2006, the Company sold the operating assets of BHER and related subsidiaries, the crude oil marketing and pipeline transportation business headquartered in Houston, Texas (see Note 16). The financial information of BHER was previously reported in the Energy marketing and transportation segment and has been reclassified to Discontinued operations on the accompanying consolidated financial statements.

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 16). The financial information of Black Hills FiberSystems, Inc. has been reclassified into Discontinued operations on the accompanying consolidated financial statements.

December 31:	2006	2005
	(in thousands)	
Total assets		
Retail services:		
Electric utility	$ 474,164	$ 460,489
Electric and gas utility	266,659	163,464
Wholesale energy:		
Oil and gas	400,476	242,753
Power generation	702,137	732,273
Coal mining	58,584	57,805
Energy marketing	324,546	327,086
Corporate	16,686	14,230
Discontinued operations	1,424	122,158
Total assets	$ 2,244,676	$ 2,120,258
Capital expenditures and asset acquisitions		
Retail services:		
Electric utility	$ 24,992	$ 18,162
Electric and gas utility	107,348	30,536
Wholesale energy:		
Oil and gas	158,846	71,799
Power generation	8,557	6,095
Coal mining	5,807	6,517
Energy marketing	928	80
Corporate	1,972	3,090
Total capital expenditures and asset acquisitions	$ 308,450	$ 136,279
Property, plant and equipment		
Retail services:		
Electric utility	$ 675,635	$ 653,327
Electric and gas utility	247,255	130,790
Wholesale energy:		
Oil and gas	486,596	322,749
Power generation	737,483	734,032
Coal mining	82,458	77,625
Energy marketing	2,243	1,497
Corporate	10,726	8,539
Total property, plant and equipment	$ 2,242,396	$ 1,928,559

December 31:	2006	2005 (in thousands)	2004
External operating revenues			
Retail services:			
Electric utility	$ 190,814	$ 186,806	$ 172,774
Electric and gas utility	132,189	110,875	—
Wholesale energy:			
Oil and gas	95,078	87,536	59,191
Power generation	154,985	158,399	158,037
Coal mining	22,405	21,376	19,669
Energy marketing	51,231	37,722	25,538
Corporate	46	771	761
Total external operating revenues	$ 646,748	$ 603,485	$ 435,970
Intersegment operating revenues			
Retail services:			
Electric utility	$ 2,352	$ 2,199	$ 971
Wholesale energy:			
Oil and gas	—	13	343
Coal mining	13,877	12,901	12,298
Corporate	—	—	2,672
Intersegment eliminations	(6,095)	(5,057)	(6,711)
Total intersegment operating revenues[(a)]	$ 10,134	$ 10,056	$ 9,573

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

	2006	2005	2004
Depreciation, depletion and amortization			
Retail services:			
Electric utility	$ 19,801	$ 19,543	$ 18,873
Electric and gas utility	5,415	4,532	—
Wholesale energy:			
Oil and gas	30,176	22,114	13,028
Power generation	31,907	35,583	34,535
Coal mining	5,211	4,366	5,142
Energy marketing	512	355	140
Corporate	1,061	1,623	1,261
Total depreciation, depletion and amortization	$ 94,083	$ 88,116	$ 72,979
Operating income (loss)			
Retail services:			
Electric utility	$ 40,002	$ 36,044	$ 43,809
Electric and gas utility	5,954	3,053	—
Wholesale energy:			
Oil and gas	26,088	31,605	19,181
Power generation	58,817	(2,154)	47,934
Coal mining	6,916	7,892	8,454
Energy marketing	24,008	19,198	10,598
Corporate	(8,399)	(13,787)	(1,306)
Intersegment eliminations	(714)	—	—
Total operating income	$ 152,672	$ 81,851	$ 128,670

December 31:	2006	2005 (in thousands)	2004
Interest income			
Retail services:			
Electric utility	$ 2,970	$ 258	$ 696
Electric and gas utility	238	613	—
Wholesale energy:			
Oil and gas	156	39	12
Power generation	17,986	20,914	24,559
Coal mining	1,858	1,304	1,393
Energy marketing	1,859	1,157	668
Corporate	61,312	23,597	15,626
Intersegment eliminations	(84,598)	(46,165)	(41,256)
Total interest income	$ 1,781	$ 1,717	$ 1,698
Interest expense			
Retail services:			
Electric utility	$ 14,769	$ 12,907	$ 16,019
Electric and gas utility	1,407	708	—
Wholesale energy:			
Oil and gas	7,120	3,922	1,578
Power generation	48,709	45,069	49,758
Coal mining	427	—	226
Energy marketing	2,139	1,498	551
Corporate	61,053	30,694	21,216
Intersegment eliminations	(84,598)	(46,165)	(41,256)
Total interest expense	$ 51,026	$ 48,633	$ 48,092
Income taxes			
Retail services:			
Electric utility	$ 10,129	$ 5,743	$ 9,512
Electric and gas utility	1,478	844	—
Wholesale energy:			
Oil and gas	7,127	10,511	5,315
Power generation	8,612	(558)	6,711
Coal mining	2,819	2,641	2,574
Energy marketing	6,419	5,021	5,079
Corporate	(2,532)	(7,158)	(3,092)
Intersegment eliminations	(250)	—	—
Total income taxes	$ 33,802	$ 17,044	$ 26,099
Income (loss) from continuing operations			
Retail services:			
Electric utility	$ 18,724	$ 18,005	$ 19,209
Electric and gas utility	5,464	2,114	—
Wholesale energy:			
Oil and gas	12,736	17,905	12,200
Power generation	19,901	(12,524)[(b)]	15,562
Coal mining	5,877	6,947	7,463
Energy marketing	17,322	13,836	5,637
Corporate	(5,514)	(13,491)	(3,786)
Intersegment eliminations	(464)	—	(4)
Total income from continuing operations	$ 74,046	$ 32,792	$ 56,281

(b) Loss from continuing operations includes a $33.9 million after-tax impairment charge for long-lived assets as described in Note 11.

(21) ACQUISITIONS

Oil and Gas Assets

On March 17, 2006, the Company acquired certain oil and gas assets of Koch Exploration Company, LLC, for approximately $51.4 million. The associated acreage position is located in the Piceance Basin in Colorado and includes approximately 40 Bcfe of proved reserves, including approximately 31 Bcfe of proved undeveloped reserves, which are substantially all gas. The acquisition includes 63 producing wells and majority interests in associated midstream and gathering assets.

In addition, on August 30, 2006, the Company acquired from a third party most of the remaining working interests associated with the property acquired in March 2006 from Koch Exploration Company. The acquisition includes approximately 22.4 Bcfe of proven reserves, of which 17.9 Bcfe are proved undeveloped reserves. As part of the transaction, the Company also acquired rights to more than 15,000 net acres of undeveloped leasehold adjacent or near existing operations in the Piceance Basin of Colorado. The purchase price for the transaction was approximately $24.0 million. With completion of the acquisition, the Company's leasehold position in the Piceance Basin totals approximately 75,000 net acres.

Cash payments for these acquisitions were funded with a combination of operating cash flows and short-term borrowings. Operations of these assets prior to acquisition were not material to the Company's consolidated operations; therefore no pro-forma information has been presented herein.

(22) SUBSEQUENT EVENTS

Acquisition of Utility Assets

On February 7, 2007 the Company entered into a definitive agreement with Aquila, Inc. for the asset acquisition of Aquila's regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The purchase price of the assets is $940 million, subject to closing adjustments. In conjunction with this agreement, the Company has entered into a binding agreement with a group of lenders for a committed acquisition credit facility as a bridge financing for the transaction.

The purchase is conditioned on the completion of the acquisition of the outstanding shares of Aquila by Great Plains immediately following the sale of the regulated utilities to the Company. The purchase is also subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Service Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions.

This transaction would add approximately 93,000 electric utility customers and 523,000 gas utility customers to the Company's utility operations.

Private Placement of Common Stock

On February 22, 2007, the Company completed the issuance and sale of approximately 4.17 million shares of Common Stock at a price of $36.00 per share in a private placement to institutional investors pursuant to a Securities Purchase Agreement dated as of February 14, 2007. The Company used the net proceeds from this offering for debt reduction. The shares of Common Stock were not registered under the Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

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

BHEP has operating and non-operating interests in 1,136 oil and gas properties in eleven states and holds leases on approximately 394,000 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):

	2006	2005	2004
Acquisition of properties:			
Proved	$ 64,265	$ 4,110	$ 1,578
Unproved	19,336	6,779	231
Exploration costs	21,752	7,194	6,094
Development costs	53,080	58,669	39,258
	$ 158,433	$ 76,752	$ 47,161

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2006, 2005 and 2004, 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.

	2006		2005		2004	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of Bbls of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	6,835	128,573	5,239	141,983	5,389	124,062
Production	(401)	(11,512)	(396)	(10,854)	(432)	(9,456)
Additions – Extensions/Acquisitions	118	72,337	1,548	21,756	685	65,965
Property sales	—	—	—	—	(39)	(1,698)
Revisions to previous estimates	(829)	(24,644)	444	(24,312)	(364)	(36,890)
Balance at end of year	5,723	164,754	6,835	128,573	5,239	141,983
Proved developed reserves at end of year included above	4,723	87,891	4,694	80,959	4,608	80,366
Year-end prices (NYMEX)	$ 61.05	$ 5.52	$ 61.04	$ 11.23	$ 43.45	$ 6.15
Year-end prices (average well-head)	$ 52.06	$ 5.34	$ 58.52	$ 9.06	$ 41.19	$ 5.55

The 2006 reserve reconciliation reflects a 29.6 Bcfe downward revision to previous estimates. This downward revision is primarily associated with lower than expected production results from portions of the East Blanco Field, New Mexico; the Finn-Shurley Field in Wyoming; and the Big Springs Area, Nebraska. The revisions at East Blanco, accounting for approximately 78 percent of the total, are attributed to lower than expected production results from drilling activities to delineate portions of the field. Reductions of proved non-producing and proved undeveloped reserves were prompted by the reductions from the delineation drilling. At Finn-Shurley, lower than expected performance and reduced reservoir pressure found during delineation drilling in sections of the field, prompted revision of previous reserve forecasts. Finn-Shurley revisions account for approximately 18 percent of the total. Associated proved undeveloped locations to this development drilling were also revised downward. Steep production decline and water encroachment in the majority of the wells at Big Springs prompted revision of previous estimates of the proved developed producing reserves. Revisions at Big Springs account for approximately 7 percent of the total. The decrease in natural gas and oil prices as of December 31, 2006 compared to December 31, 2005 also contributed to the revision.

Capitalized Costs

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

	2006	2005	2004
Unproved oil and gas properties	$ 36,936	$ 15,390	$ 20,148
Proved oil and gas properties	409,984	271,881	209,748
	446,920	287,271	229,896
Accumulated depreciation, depletion & amortization and valuation allowances	(112,020)	(85,488)	(75,870)
Net capitalized costs	$ 334,900	$ 201,783	$ 154,026

Results of Operations

Following is a summary of results of operations for producing activities for the years ended December 31, (in thousands):

	2006	2005	2004
Revenues			
Sales	$ 94,682	$ 87,235	$ 57,869
Production costs	27,487	23,897	19,991
Depreciation, depletion & amortization and valuation provisions	27,420	20,396	11,497
	54,907	44,293	31,488
Income tax expense	7,180	10,412	5,342
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ 32,595	$ 32,530	$ 21,039

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):

	2006	2005	2004
Future cash inflows	$ 1,238,962	$ 1,655,378	$ 1,044,098
Future production and development costs	(553,580)	(586,829)	(409,478)
Future income tax expense	(184,373)	(324,306)	(144,053)
Future net cash flows	501,009	744,243	490,567
10 percent annual discount for estimated timing of cash flows	(233,484)	(346,774)	(181,368)
Standardized measure of discounted future net cash flows	$ 267,525	$ 397,469	$ 309,199

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):

	2006	2005	2004
Standardized measure – beginning of year	$ 397,469	$ 309,199	$ 202,122
Sales and transfers of oil and gas produced, net of production costs	(64,367)	(70,400)	(45,266)
Net changes in prices and production costs	(233,599)	301,055	55,916
Extensions, discoveries and improved recovery, less related costs	30,114	71,544	168,516
Net changes in future development costs	38,256	(4,302)	21,852
Revisions of previous quantity estimates	(106,124)	(185,878)	(96,419)
Accretion of discount	56,002	39,445	26,534
Net change in income taxes	91,556	(77,306)	(22,028)
Purchases of reserves	58,218	14,112	4,062
Sales of reserves	—	—	(6,090)
Standardized measure – end of year	$ 267,525	$ 397,469	$ 309,199

(24) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth selected unaudited historical operating results and market data for each quarter of 2006 and 2005.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2006				
Operating revenues	$ 171,890	$ 153,813	$ 157,608	$ 173,571
Operating income	39,369	32,431	40,946	39,926
Income from continuing operations	18,561	12,368	22,199	20,918
Income (loss) from discontinued operations, net of taxes	7,590	(611)	81	(87)
Net income	26,151	11,757	22,280	20,831
Net income available for common stock	26,151	11,757	22,280	20,831
Earnings (loss) per common share:				
Basic -				
Continuing operations	$ 0.56	$ 0.37	$ 0.67	$ 0.63
Discontinued operations	0.23	(0.02)	—	—
Total	$ 0.79	$ 0.35	$ 0.67	$ 0.63
Diluted -				
Continuing operations	$ 0.55	$ 0.37	$ 0.66	$ 0.62
Discontinued operations	0.23	(0.02)	—	—
Total	$ 0.78	$ 0.35	$ 0.66	$ 0.62
Dividends paid per share	$ 0.33	$ 0.33	$ 0.33	$ 0.33
Common stock prices				
High	$ 40.00	$ 37.52	$ 36.86	$ 37.95
Low	$ 32.92	$ 32.46	$ 33.20	$ 33.38

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2005				
Operating revenues	$ 142,420	$ 142,385	$ 149,008	$ 179,728
Operating income (loss)	33,271	33,151	(30,551)	45,980
Income (loss) from continuing operations	15,254	15,315	(23,784)	26,007
Income (loss) from discontinued operations, net of taxes	486	(345)	(119)	606
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	$ 0.47	$ 0.47	$ (0.73)	$ 0.78
Discontinued operations	0.02	(0.01)	—	0.02
Total	$ 0.49	$ 0.46	$ (0.73)	$ 0.80
Diluted -				
Continuing operations	$ 0.46	$ 0.46	$ (0.73)	$ 0.77
Discontinued operations	0.02	(0.01)	—	0.02
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

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, 2006. 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 86 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, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our directors and information required by Items 401, 405, 407(c)(3), 407(d)(4) and 407 (d)(5) of Regulation S-K is incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 22, 2007.

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 executive compensation and transactions and compensation committee interlocks and insider participation is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 22, 2007.

The Compensation Committee Report is also incorporated herein by reference to our Proxy Statement, however it is deemed to be "furnished" and shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.

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 is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 22, 2007.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2006 with respect to our equity compensation plans. These plans include the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the 2005 Omnibus Incentive Plan.

Equity Compensation Plan Information			
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders[1]	844,521 [2]	$29.61[2]	1,068,258 [3]
Equity compensation plans not approved by security holders	—	—	—
Total	844,521	$29.61	1,068,258

[1] Consists of the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the 2005 Omnibus Incentive Plan.

[2] Includes 119,643 full value awards outstanding as of December 31, 2006, comprised of restricted stock units, performance shares and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares or common stock units. In addition, 98,639 shares of unvested restricted stock were outstanding as of December 31, 2006, which are not included in the above table because they have already been issued.

[3] Shares available for issuance are from the 2005 Omnibus Incentive Plan. The 2005 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 22, 2007.

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 22, 2007.

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, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2006, and the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2006, and have issued our reports thereon dated February 27, 2007 (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 No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, effective January 1, 2006, and Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, effective as of December 31, 2006); such consolidated financial statements and reports are included in your 2006 Annual Report on Form 10-K. Our audits also included the consolidated financial statement schedule of the Corporation listed in Item 15(a)(2). The consolidated financial statement schedule is the responsibility of the Corporation's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 27, 2007

(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

Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2006, 2005 and 2004.

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
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

		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:					
2006	$ 4,685	$ 2,811	$ (5)	$ (3,289)	$ 4,202
2005	4,196	(277)	1,778	(1,012)	4,685
2004	6,726	803	—	(3,333)	4,196

(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)).
2.2*	Agreement and Plan of Merger among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp. and Black Hills Corporation dated as of February 6, 2007 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on February 8, 2007).
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10.4*†	2007 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on February 5, 2007).
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10.8*†	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2001).
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10.16*†	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).
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10.18†	Fourth Amendment to the Outside Directors Stock Based Compensation Plan.
10.19*†	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1998).
10.20*†	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).

10.21*† Severance and Release Agreement between Russell L. Cohen and Black Hills Corporation (filed as Exhibit 10 to the Registrant's Form 8-K filed December 11, 2006).

10.22* 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).

10.23* 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).

10.24* 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).

10.25* Second Amended and Restated Credit Agreement made as of the 1st day of June, 2006, among Enserco Energy Inc., the borrower, Fortis Capital Corp., as administrative agent, documentation agent and collateral agent, BNP Paribas, US Bank National Association, Societe Generale, and the Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch. (filed as Exhibit 10.1 to the Registrant's Form 8-K filed June 7, 2006).

10.26* 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).

10.27* 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).

10.28* 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).

10.29* 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).

10.30* Amended and Restated Credit Agreement dated as of May 24, 2006, among Wygen Funding, Limited Partnership, the Lenders parties thereto, the Financial Institutions parties thereto, as Liquidity Purchasers; and Calyon New York Branch, as Administrative Agent, Bookrunner and Lead Arranger (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2006).

10.31* Amended and Restated Guarantee dated as of May 24, 2006, from Black Hills Corporation, as Guarantor, in favor of Wygen Funding, Limited Partnership (filed as Exhibit 10.3 to the

Registrant’s Form 10-Q for the quarterly period ended June 30, 2006).

10.32*	Commitment Letter between Black Hills Corporation and ABN AMRO BANK, N.V. and certain other financial institutions dated as of February 6, 2007 (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on February 8, 2007).
10.33*	Partnership Interests Purchase Agreement among Aquila, Aquila Colorado, LLC, Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp., dated as of February 6, 2007 (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on February 8, 2007).
10.34*	Asset Purchase Agreement among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp., dated as of February 6, 2007 (filed as Exhibit 10.3 to the Registrant’s Form 8-K filed on February 8, 2007).
10.35*	Securities Purchase Agreement by and among Black Hills Corporation and the Purchasers set forth therein, dated as of February 14, 2007 (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on February 22, 2007).
10.36*	Registration Rights Agreement by and among Black Hills Corporation and the Purchasers set forth therein, dated as of February 22, 2007 (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on February 22, 2007).
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.
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32.1	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 1, 2007

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 1, 2007
/S/ MARK T. THIES Mark T. Thies, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	March 1, 2007
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 1, 2007
/S/ JACK W. EUGSTER Jack W. Eugster	Director	March 1, 2007
/S/ JOHN R. HOWARD John R. Howard	Director	March 1, 2007
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 1, 2007
/S/ RICHARD KORPAN Richard Korpan	Director	March 1, 2007
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	March 1, 2007
/S/ JOHN B. VERING John B. Vering	Director	March 1, 2007
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 1, 2007

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