BLACK HILLS CORP /SD/
Form 10-K
February 29, 2008

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

Form 10-K

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

For the fiscal year ended December 31, 2007

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

For the transition period from ___________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota

625 Ninth Street
Rapid City, South Dakota 57701

IRS Identification Number 46-0458824

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

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

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes x No o

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

Yes o No x

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

Yes x No o

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

Yes o No x

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

At June 30, 2007 $1,484,649,581

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, 2008
Common stock, $1.00 par value	37,818,954 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 2008 Annual Meeting of Stockholders to be held on May 20, 2008, 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.
ARB	Accounting Research Bulletin
ARB No. 51	ARB No. 51, Consolidated Financial Statements
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
CAMR	Clean Air Mercury Rule
CARB	California Air Resource Board
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
CO_2	Carbon Dioxide
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 04-6	EITF Issue No. 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry
EMF	Electric and Magnetic Fields
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
GAAP	Generally Accepted Accounting Principles
GCA	Gas Cost Adjustment
Great Plains	Great Plains Energy Incorporated
IGCC	Integrated Gasification Combined Cycle
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 Investors Service, Inc.
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
NPC	Nevada Power Company
NPDES	National Pollutant Discharge Elimination System
PCBs	Polychlorinated Biphenyls
PNM	PNM Resources, Inc.
PSCo	Public Service Company of Colorado
PUCN	Public Utilities Commission of Nevada
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
SAB	Staff Accounting Bulletin
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 88	SFAS 88, Employer s Accounting for Settlement and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
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 132(R)	SFAS 132(R), Employer s Disclosures about Pensions and Other Postretirement Benefits an amendment of FASB Statements No. 87, 88 and 106
SFAS 133	SFAS 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141(R)	SFAS 141 (Revised 2007), Business Combinations
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
SFAS 160	SFAS 160, Non-controlling Interest in Consolidated Financial Statements an amendment of ARB No. 51
SO_2	Sulfur Dioxide
S&P	Standard & Poor s Rating Service
TSA	Transmission Service Agreement
USDHS	U.S. Department of Homeland Security
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 in other reports that we file with the SEC from time to time, 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 and to finance these acquisitions on attractive terms;

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 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 EPA 2005;

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

The timing, market liquidity, 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, financial liquidity 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 of any such outcome or related settlements on our financial condition or results of operations;

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: Utilities and Non-regulated energy (previously referred to as Retail Services and Wholesale Energy, respectively).

Utilities Group

Our Utilities 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 65,100 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 39,400 electric and 33,000 natural gas customers in Cheyenne, Wyoming and vicinity. We acquired Cheyenne Light on January 21, 2005.

Non-regulated Energy Group

Our non-regulated 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 the assets of Aquila s electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa along with the associated assets and 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 612,000 new utility customers (92,000 electric customers and 520,000 gas customers) to the 137,500 utility customers (104,500 electric customers and 33,000 gas customers) we currently serve. Other assets in the transaction include a customer service center and centralized natural gas operations in Nebraska.

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 assets of the regulated utilities to us. During October 2007, Great Plains and Aquila shareholders approved of the merger. The purchase is also subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions. We have filed all necessary applications for the state and federal regulatory reviews and approvals required for the proposed transaction. Thus far, we have obtained state regulatory approval for the transfer of ownership in Iowa, Nebraska and Colorado. In addition, during February 2008 settlements were reached with all parties to the proceedings in Kansas and are pending approval by the Kansas regulators. At the federal level, the FERC has approved our acquisition of the Colorado Electric operation, and antitrust clearance has been obtained from the Federal Trade Commission.

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.

Utilities Group

Our Utilities 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 system serves approximately 65,100 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 90 percent of Black Hills Power s retail electric revenues in 2007 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, 2007 was comprised of 28 percent commercial, 23 percent residential, 13 percent contract wholesale, 18 percent wholesale off-system, 11 percent industrial and 7 percent municipal sales and other revenue. We provide service to approximately 87 percent of our large commercial and industrial customers under long-term contracts.

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. In December 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 of rates for changes in energy, fuel and transmission costs, effective January 1, 2007. The cost adjustments 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. 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.

Since 1995, Black Hills Power has been a net producer of energy. Black Hills Power reached its peak system load of 430 MW in July 2007, with an average system load of 256 MW for the year ended December 31, 2007. 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. 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. Our 295 MW of low-cost, coal-fired resources supports most of our native load requirements and positions us for these wholesale off-system sales.

Power Sales Agreements. A portion of Black Hills Power s current load is sold under long term contracts. Key contracts include:

an agreement with MDU to serve the Sheridan, Wyoming electric service territory, effective through the end of 2016, under which we supply up to 74 MW of capacity and energy for Sheridan, Wyoming; and

an agreement with the City of Gillette, Wyoming, to provide the city s first 23 MW of capacity and energy. The agreement renews automatically and requires a seven year notice of termination. As of December 31, 2007, neither party to the agreement had given a 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.

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 delivered by truck from our WRDC coal mine.

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 delivered by truck from our WRDC coal mine.

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. Black Hills Power has rate adjustment mechanisms in Montana and South Dakota which provide for pass-through of certain costs related to the purchase, production and/or transmission of electricity. Black Hills Power is also subject to the jurisdiction of the FERC with respect to accounting practices and wholesale electricity sales. Black Hills Power has been granted market-based rate authority by the FERC and is not required to file cost-based tariffs for wholesale electric rates. Rates charged by Black Hills Power for use of its transmission system are subject to regulation by the FERC.

Combination Electric and Gas Utility Segment

Electric System. Cheyenne Light s electric system serves approximately 39,400 customers in Cheyenne, Wyoming and vicinity, with a peak load of 171 MW and an average load of 114 MW. Power was supplied to Cheyenne Light under an all-requirements contract with PSCo, which expired at the end of 2007. For power needs subsequent to 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 also constructed a 95 MW coal-fired plant (Wygen II) adjacent to the WRDC coal mine near Gillette, Wyoming, which was placed into commercial service on January 1, 2008. In November 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 anticipated to provide up to 30 MW of renewable power to Cheyenne Light beginning in September 2008. A portion of this renewable power may be contracted to Black Hills Power.

Cheyenne Light and Black Hills Power are parties to an affiliate agreement whereby Cheyenne Light has the ability to sell excess energy from its generating resources to Black Hills Power. The transfer price under the agreement through the first quarter of 2013 is set at the variable cost of energy under Cheyenne Light s wholesale contract with our Wygen I plant. The agreement became effective on January 1, 2008.

Natural Gas System. Cheyenne Light s natural gas distribution system serves approximately 33,000 natural gas customers in the City of Cheyenne and other portions of Laramie County, Wyoming. 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 and wholesale electricity sales. 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 filings are made at least annually and GCA filings at least quarterly. We continually monitor these cost recovery levels and are allowed to file 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 November 2007, the WPSC approved general rate increases of $6.7 million for electric rates and $4.4 million for natural gas rates to provide for increased costs of providing service. The allowed rate of return on equity is 10.9 percent based on a capital structure that is 54 percent equity and 46 percent debt. In addition, the electric rate increase includes placing the 95 megawatt, coal-fired Wygen II power plant into rate base. The WPSC also approved a new pass-through mechanism for Cheyenne Light s electric business. For calendar years beginning in 2008, the annual increase or decrease for transmission, fuel, and purchased power costs is passed on to customers, subject to a $1.0 million threshold. Under its tariff, Cheyenne Light collects or refunds 95 percent of the increase or decrease that is in excess of the $1.0 million threshold. For changes in these costs that are less than the $1.0 million annual threshold, Cheyenne Light absorbs the increase and likewise retains the savings. The new rates and tariffs were effective January 1, 2008.

Business Characteristics

The following business characteristics are common within our Utilities 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 exists in varying degrees for our Utilities 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 certain industrial and large customers have the ability to own or operate facilities to generate their own electricity, and under some circumstances, choose their electricity provider. 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 recent 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 energy, 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 also amended portions of the Federal Power Act and PURPA.

PURPA. The enactment of PURPA in 1978 provided incentives for the development of qualifying cogeneration facilities and small power production facilities that utilized certain alternative or renewable fuels, referred to as qualifying facilities, or 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. We are subject to federal, state and local laws and regulations with regard to air and water quality, solid waste disposal, federal health and safety regulations, and other environmental matters. Environmental laws, regulations and issues affecting the Utilities group include, but are not limited to:

<u>Clean Air Act</u>. The Clean Air Act as well as state laws and regulations impacting air emissions affect all our generating units. Title IV of the Clean Air Act requires certain fossil-fuel-fired combustion devices to hold SO_2 allowances for each ton of sulfur dioxide emitted. Title IV applies to our Neil Simpson II, Neil Simpson CT, Lange CT, Wyodak and Wygen II plants. 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 2036, 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 SO_2 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 requires that all of our generation facilities obtain operating permits. All of our existing facilities subject to this requirement have received Title V permits.

Clean Air Mercury Rule. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit overturned the EPA s CAMR. CAMR established limits for mercury emissions from coal-fired power plants subject to Title IV of the Clean Air Act and created a market-based cap-and-trade program. The EPA is evaluating whether to appeal the decision or propose new rules. The effects of any new rules regarding mercury reduction cannot be determined at this time and may require us to make significant investments at our power generating facilities. The Wygen II plant, placed into commercial operation in January 2008, utilizes emissions control technology which reduces mercury emissions and is required under Title IV of the Clean Air Act to monitor mercury emissions.

Clean Water Act. Our facilities are 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 the Clean Water Act and govern overall water/wastewater discharges through NPDES permits. 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 under this program have their required plans in place.

Toxic Substance Control Act. Under the federal Toxic Substance Control Act, the EPA has issued regulations that specify procedures for use, handling and disposal of PCBs. PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the Toxic Substance 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.

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, Wygen II, 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.

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 solid waste. In that event, the government regulator could hold those entities that disposed of such waste responsible for such treatment.

U.S. Department of Homeland Security. Under regulations promulgated in November 2007, our facilities were required to review chemical inventories for comparison to certain reporting triggering thresholds, with a reporting due date of January 22, 2008. This exercise and required reporting has been completed. In 2008, the USDHS will contact us regarding a determination of any required security measures to be implemented.

Electric and Magnetic Fields. Research on potential adverse health effects from exposure to EMF continues. To date, no definite relationship between EMF and health risks has been clearly demonstrated. EMF remains the subject of ongoing studies and evaluations and the implications of any new reports have not yet been determined. These reports may raise the profile of the EMF issue for electric companies. We are monitoring the research but cannot predict the impact, if any, the EMF issue may have on the Company in the future.

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Global Climate Change and Renewable Energy Mandates. Many states have enacted, and others are considering, some form of mandatory renewable energy standard requiring utilities to meet certain thresholds for the production or use of renewable energy. Many states have also either enacted or are considering legislation setting greenhouse gas emissions reduction targets. Additionally, federal legislation for both renewable energy standards and greenhouse gas emission reductions are also under consideration. While currently there are no regulations controlling greenhouse gas emissions from our Black Hills Power and Cheyenne Light generation units and no renewable energy mandates for the regulatory jurisdictions in which our utilities operate, we believe that it is possible that such programs may be developed in the near future. We anticipate significant additional costs to comply with any federally or state mandated greenhouse gas reductions or limits on CO_2 emissions. In addition to legislative activity, climate change issues are the subject of a number of lawsuits whose outcomes could impact the utility industry.

Other requirements. We have incurred, and expect to continue to incur, substantial capital and operating and maintenance costs to comply with evolving environmental requirements primarily associated with the operations of our coal-fired generating units. While these evolving requirements will impact the operation of existing and new coal-fired and other fossil-fuel generating units, it is virtually certain that environmental requirements placed on the operations of these generating units will continue to become more restrictive.

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 warmer 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.

Non-regulated Energy Group

Our Non-regulated 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; produces coal, natural gas and crude oil primarily in the Rocky Mountain region; and markets and stores natural gas and crude oil. The Non-regulated energy group consists of four business segments for reporting purposes:

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

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Oil and Gas Segment

Our oil and gas segment, which operates through BHEP and its subsidiaries, acquires, explores for, develops and produces natural gas and crude oil which are then sold into the commodity markets. As of December 31, 2007, we held operating interests in oil and gas properties including approximately 628 gross and 572 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 Nebraska section of the Denver Julesberg Basin. 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 hold non-operated interests in oil and natural gas properties including approximately 608 gross and 78 net wells located in California, Colorado, Louisiana, Montana, North Dakota, Oklahoma, Texas and Wyoming.

We own a 44.7 percent non-operated 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, 2007, we had total reserves of approximately 208 Bcfe, of which natural gas comprised 83 percent 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 37 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, 22 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties and 31 percent are located in the Piceance Basin of western Colorado.

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, 2007 and 2006. The 2007 information is based on reports prepared by Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm located in Fort Worth, Texas. This is the first year Cawley, Gillespie & Associates, Inc. has served as the reserve auditor for BHEP. Ralph E. Davis Associates, Inc. prepared the reserve audit reports for the information presented as of December 31, 2006. Reserves were determined consistent with SEC requirements 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, 2007			December 31, 2006		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*
Wyoming	4,954	15,164	44,888	4,617	9,741	37,443
New Mexico	3	45,646	45,664	19	44,171	44,285
Colorado		23,497	23,497		23,052	23,052
Montana	35	3,034	3,244	41	3,953	4,199
Nebraska		677	677		1,810	1,810
Other states	103	4,504	5,122	46	5,164	5,440
Total Proved Developed Reserves	5,095	92,522	123,092	4,723	87,891	116,229

*Oil Bbls are multiplied by six to convert to Mcfe.

Proved Undeveloped Reserves:	December 31, 2007			December 31, 2006		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	555	1,655	4,985	997	1,474	7,456
New Mexico		24,293	24,293		26,653	26,653
Colorado		49,221	49,221		47,437	47,437
Montana		2,453	2,453		770	770
Nebraska						
Other states	157	2,820	3,762	3	529	547
Total Proved Undeveloped Reserves	712	80,442	84,714	1,000	76,863	82,863

Total Proved Reserves:	December 31, 2007			December 31, 2006		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	5,509	16,819	49,873	5,614	11,215	44,899
New Mexico	3	69,939	69,957	19	70,824	70,938
Colorado		72,718	72,718		70,489	70,489
Montana	35	5,487	5,697	41	4,723	4,969
Nebraska		677	677		1,810	1,810
Other states	260	7,324	8,884	49	5,693	5,987
Total Proved Reserves	5,807	172,964	207,806	5,723	164,754	199,092

	December 31, 2007	December 31, 2006
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	59%	58%
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	41%	42%
Present value of estimated future net revenues, before tax (in thousands)	$ 424,849	$ 338,521

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

	December 31, 2007	December 31, 2006
Gas per Mcf	$ 5.88	$ 5.34
Oil per Bbl	$ 83.23	$ 52.06

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2007, we participated in drilling 115 gross (37.84 net) development and exploratory wells, with a success rate of approximately 93 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,	2007		2006		2005	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	3.67		28.20		1.36	1.00
New Mexico	17.30		21.00	1.00	36.28	1.00
Montana	8.98	0.45	3.42	0.02	3.22	
Nebraska		2.00		1.00	17.00	
Other states	2.35		0.20		3.81	0.67
Total	32.30	2.45	52.82	2.02	61.67	2.67

Year ended December 31,	2007		2006		2005	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	0.61		0.04		0.10	
New Mexico	1.60		1.00		0.80	
Montana	0.27	0.25	2.35	0.50	3.74	0.68
Nebraska						0.50
Other states	0.37		1.28		0.57	0.15
Total	2.85	0.25	4.67	0.50	5.21	1.33

As of December 31, 2007, we were participating in the drilling of 19 gross (3.4 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the year ended December 31, 2007 were not material to the overall operations of this segment.

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:

	2007	2006	2005
Production:			
Natural gas (Mcf)	12,172,400	12,005,600	11,372,000
Oil (Bbl)	409,040	401,440	395,550
Total (Mcfe)	14,626,640	14,414,240	13,745,300
Average price, net of hedges:			
Natural gas (Mcf)	$ 6.19	$ 6.11	$ 6.36
Oil (Bbl)	$ 60.29	$ 50.75	$ 35.99
Average production cost (per Mcfe):			
LOE	$ 0.98	$ 1.19	$ 0.93
Production and other taxes	0.70	0.67	0.77
Total	$ 1.68	$ 1.86	$ 1.70

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2007:

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	404	185	589	303.17	12.01	315.18
New Mexico	2	190	192	1.95	180.83	182.78
Colorado	1	90	91		62.19	62.19
Montana	3	198	201	0.47	41.07	41.54
Nebraska		36	36		27.00	27.00
Other states	7	120	127	1.06	21.93	22.99
Total	417	819	1,236	306.65	345.03	651.68

Acreage

The following table summarizes our undeveloped, developed and total acreage by state as of December 31, 2007 (in thousands):

	Undeveloped Gross	Net	Developed Gross	Net	Total Gross	Net
Wyoming	44,731	33,657	24,098	15,083	68,829	48,740

New Mexico	39,889	39,464	24,623	22,371	64,512	61,835
Colorado	49,369	34,615	40,653	32,736	90,022	67,351
Montana	719,863	139,548	95,460	17,573	815,323	157,121
Nebraska	30,620	27,589	56,228	45,444	86,848	73,033
Other states	93,392	23,576	24,121	4,830	117,513	28,406
Total	977,864	298,449	265,183	138,037	1,243,047	436,486

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, pollution standards and protection of the environment and wildlife resources, protection of historical artifacts and protection of public health, safety and welfare. 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, that create areas of overlap and ambiguity 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 ever-changing regulatory standards.

These regulations often require multiple permits and bonds to drill or operate wells, and establish rules regarding the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the timing of when drilling and construction activities can be conducted relative to various wildlife stipulations and the plugging and abandoning of wells. Our operations are also subject to various mineral 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, when voluntary pooling of lands and leases cannot be accomplished. The effect of these regulations may 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. In addition to these federal laws and associated regulations, each state we operate in has numerous laws in place with which we must also comply. The state of Colorado passed new laws in 2007 applicable to oil and natural gas development. These new laws included a complete restructuring of the Colorado Oil and Gas Conservation Commission and have charged the new commission with developing new oil and gas well permitting processes in 2008.

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 gathering 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, underground injection control disposal permits), chemical storage and use and the remediation of petroleum-product contamination. Certain states, such as Colorado, have chosen to impose storm water requirements more strict than EPA s and are taking a high profile in implementing and enforcing their requirements. We take a proactive role in working with these agencies to ensure compliance.

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 which are currently 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 22 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Generation Segment

Our power generation segment, which operates through Black Hills Generation and subsidiaries and Black Hills Wyoming, 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, 2007. We also hold minority interests in several power-related funds with a net ownership interest of 5.0 MW.

During 2007, we began construction of the Valencia generation facility. Valencia is a 149 MW simple-cycle gas turbine generating facility located near Albuquerque, New Mexico. The facility is expected to cost approximately $101.0 million to construct and is on schedule to commence commercial operations during the summer of 2008. If we fail to meet the required in-service date, significant penalties could be incurred under the delay damage provisions that are customary within agreements of this nature. We will provide the capacity and energy of the facility to Public Service Company of New Mexico under a 20-year power purchase agreement. The agreement is a customary tolling arrangement, where we receive variable and fixed fees for the plant s availability and operation, and Public Service Company of New Mexico is responsible for providing fuel for the operation. The agreement also allows Public Service Company of New Mexico the option to acquire an equity interest of up to 50 percent in the facility.

We have recently initiated a review of strategic alternatives for our non-regulated power plants located in Colorado, Nevada, New Mexico and California. We may sell all, none or a combination of these assets and expect to make a decision on any possible sale during the second quarter of 2008. Separately, we are also considering selling a 20 MW undivided interest in the Wygen I plant. If we elect to sell this undivided interest, we intend to retain the remaining interest and continue operating control of the plant.

Portfolio Management. We maintain a geographically diverse portfolio of power plants in our Non-regulated 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 it is 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, 2007, 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
Valmont	Gas	CO	80.0	100%	80.0	2000
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 (1)	Coal	WY	90.0	100%	90.0	2003
Harbor	Gas	CA	98.0	100%	98.0	1989
Ontario	Gas	CA	12.0	100%	12.0	1984
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 hold our interest in Wygen I through a synthetic lease arrangement.

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 currently expires on July 31, 2008. We have recently negotiated a long-term tolling agreement with NPC that, if approved by the PUCN, would replace our existing contract with NPC. The agreement is part of a stipulation currently scheduled to be reviewed by the PUCN during March 2008. 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 our power plant and coal mine complex. 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 expired December 31, 2007. Upon expiration of PSCo s all-requirements power purchase agreement with Cheyenne Light, the Gillette CT power purchase agreement reverted back to Cheyenne Light.

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 2003 and is located at our Gillette energy complex. 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 in the first quarter of 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. The PSCo contract expired on December 31, 2007, and the output then reverted 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.

Harbor Cogeneration Facility. Harbor Cogeneration is a 98 MW, combined-cycle, gas-fired plant located at the Port of Long Beach, California. All of the capacity and energy of the facility is sold to SCE under a tolling agreement, which expires May 31, 2008. Subsequent to the expiration of this tolling agreement, we will sell energy from the facility on a merchant basis while we attempt to arrange a new long-term power sales agreement. 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 $8.4 million in 2008.

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 terminated in December 2007. In order to maintain QF status and the underlying power purchase agreement, the project must maintain a thermal energy host or obtain the required QF waivers. We are currently evaluating our options for maintaining QF status. We are also considering selling the plant s allocated nitrous oxide RECLAIM Trading Credits for the period subsequent to the 2010 expiration of the SCE power purchase agreement. A sale of these emissions credits would increase the likelihood of retiring the plant by 2010.

Idaho Cogeneration Facilities. Through partnership investments, we own a 50 percent interest in two QFs in Rupert and Glenns Ferry, Idaho. Rupert and Glenns Ferry are both 11 MW, combined-cycle, gas-fired plants. We account for our investment in the partnerships under the equity method of accounting. Electrical output from the facilities is sold to Idaho Power Company under 20-year Energy Sales Agreements, which expire in late 2016. The facilities also sell steam production to Idaho Fresh-Pak, Inc. under Thermal Energy Service Agreements, which also expire in late 2016. Idaho Fresh-Pak, Inc. has recently provided notice to the facilities of their intent to cease operations and discontinue steam purchases. Such an action would likely have a material adverse effect on the facilities operations, including an inability to meet QF requirements and terms of related energy sales agreements.

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 5.0 MW. We account for our investment in the funds under the equity method of accounting and as of December 31, 2007, we had a $3.0 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.	2	102.7	4.4%	4.5
Total Fund Interests		112.1		5.0

Project Development Program. We continue to 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 the capacity and energy from 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 under the 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 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, Glenns Ferry, Rupert and Ontario facilities as QFs. The enactment of EPA 2005 did 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. We are subject to a broad range of federal, state and local laws and regulations with regard to air and water quality, solid waste disposal and other environmental matters. Environmental laws, regulations and issues affecting our Power generation segment are substantially the same as those affecting our Utilities group. In addition, the Power generation segment is impacted by the following:

Clean Air Act. The Clean Air Act impacts the Power generation segment in a similar manner to the impact disclosed for our Utilities group. Title IV of the Clean Air Act applies to our Gillette CT, Wygen I, Arapahoe, Valmont, Fountain Valley, Las Vegas II and Valencia plants. We currently hold sufficient allowances credited to us as a result of sulfur removal equipment previously installed at our electric utility s Wyodak plant to apply to the operation of all of our units subject to Title IV through 2036 without requiring the purchase of any additional allowances from non-affiliated third parties. The allowances credited for the Wyodak plant are purchased from Black Hills Power at current market prices.

Title V of the federal Clean Air Act requires that all of our facilities obtain operating permits. All of our existing facilities subject to this requirement have received Title V permits.

Clean Water Act. The Clean Water Act impacts our Power generation segment in a similar manner to the impact disclosed for our Utilities group. 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.

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 reevaluating 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.

Global Climate Change. In addition to the factors discussed under this caption for the Utilities group, our Non-regulated group is impacted by regulation from several western states.

California passed the Global Warming Solutions Act of 2006. This law sets enforceable state-wide greenhouse gas emissions caps from major industries and includes penalties for non-compliance. It requires that by 2020 the state s CO_2 emissions be reduced to 1990 levels. The CARB is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases. The CARB is working with the California PUC to establish emissions performance standards for power generation. At this time, individual reduction targets have not been issued for each plant and we are unable to determine the impact of this law until these targets are established.

New Mexico and Nevada have passed legislation requiring the tracking and reporting of greenhouse gas emissions, beginning with calendar year 2008. To date there are no associated emission limitations, although we anticipate these and other states may implement such programs in the future.

Other requirements. We may incur substantial capital and operating and maintenance costs to comply with evolving environmental requirements. While these evolving requirements will impact the operation of existing and new coal-fired and other fossil-fuel generating units, it is virtually certain that environmental requirements placed on the operations of these generating units will continue to become more restrictive. Many of the long-term power sales agreements in place at our power generation facilities contain government imposition clauses that allow us to pass certain of these costs on to the power purchaser.

Coal Mining Segment

Our coal mining segment operates through our WRDC subsidiary. We mine and process low-sulfur 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 5.0 million tons of coal in 2007. 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, 2007, we had coal reserves of approximately 280 million tons, based on internal engineering studies. The reserve life is equal to approximately 43 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 95 MW Wygen II plant, which commenced commercial operation in January 2008. The plant was 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 100 MW Wygen III plant, which is currently in the development and permitting stage and, if constructed, would be expected to utilize approximately 0.6 million tons of coal per year.

Our coal mining segment sells coal to Black Hills Power and Cheyenne Light for all of their requirements under agreements that limit earnings from the related coal sales 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, Wyoming 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 agreement with Cheyenne Light provides coal for the life of the Wygen II plant, which was placed in service January 1, 2008.

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 in compliance with other permitting programs administered by various regulatory agencies.

Based on extensive reclamation studies, we currently have approximately $14.8 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 re-evaluate 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 of the WDEQ s water quality standards.

Another situation that could result in unexpected increases in costs is the current State of Wyoming reexamination 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 for specialized placement of ash at alternate approved sites within the mine due to loss of mine backfill.

Energy Marketing Segment

Through our subsidiary, Enserco, 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. Our gas and oil marketing efforts are concentrated in the Rocky Mountain, Western and Mid-continent regions of the United States and in Canada. The customers of our energy marketing segment include:

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

Our average daily marketing physical volumes for the year ended December 31, 2007 were approximately 1.7 million MMBtu of gas and approximately 8,600 Bbls of oil.

Our energy marketing operations focus primarily on producer services and wholesale natural gas marketing. The business scope is comprised of the purchase, sale, storage and transportation of natural gas and crude oil, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients.

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.

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.

Seasonality. Weather conditions affect the demand for natural gas and can be a source of volatility in natural gas prices. Both are typically higher in the fourth and first quarters of our fiscal year, resulting in higher margins. Due to these seasonal fluctuations, results of operations on a quarterly basis may not reflect results which may be realized on an annual basis.

Working Capital Practices. The natural gas storage part of the business requires significant working capital investment in the form of inventory. Those investment levels are typically highest in the second and third quarters of our fiscal year.

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 policies 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 company guarantees for energy marketing; as of December 31, 2007, we had $7.0 million of 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, a warehouse building and shop with approximately 25,200 square feet and lease 18,000 square feet of office space and 8,800 square feet for a customer call center. 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 and in Bellevue, Nebraska, we lease space for a data center.

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Employees

At January 31, 2008, we had 998 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	259
Black Hills Power [1]	326
Cheyenne Light [2]	100
Non-regulated Energy Group	313
Total[3]	998

(1) Approximately 51 percent of our Black Hills Power employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers (Local 1250), which currently expires on March 31, 2009.

(2) Approximately 74 percent of our Cheyenne Light employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers (Local 111), which currently expires on June 30, 2008.

(3) Completion of the pending Aquila acquisition would more than double our number of employees. Approximately 40 percent of these employees are represented by four separate collective bargaining agreements with the International Brotherhood of Electrical Workers and Communications Workers of America.

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.

We have 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 approvals from the FERC and various utility regulatory, antitrust and other authorities in the United States. Several approvals were received during 2007. As we proceed to obtain the remaining approvals, 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.

In addition, the participating financial institution commitments to fund our $1.0 billion acquisition facility expire on August 5, 2008, and the facility terminates on February 5, 2009. Delays that prevent the closing of the acquisition prior to August 5, 2008 could require us to find replacement financing, for which we may incur a substantial amount of additional financing-related costs. If we were unable to find acceptable replacement financing, it could 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 effectively 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 the acquisition is subject to a number of uncertainties. We cannot provide assurance 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 have taken 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 negatively 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 provide assurance 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.

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, the WPSC and the MTPSC. 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, future capital expenditures 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, changes in future capital expenditures and fluctuations 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 could impair our ability to execute our growth strategy.

Execution of our future growth plan is dependent on successful 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, state, local or tribal 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 newly acquired assets.

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 other 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 interest expense under some of our existing debt obligations, including borrowings made under our credit agreements and the $1.0 billion acquisition facility.

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 during scheduled and unscheduled outages;
- the unavailability or increased cost of equipment and labor supply;
- supply interruptions;
- work stoppages;
- labor disputes;
- costs to comply with future environmental laws and regulations;
- opposition by members of public or special-interest groups;
- 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 recent years, 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 hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results and our stock price could be adversely affected as a result.

We use various contracts and derivatives, including futures, forwards, options and swaps, to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the items being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin is essentially unchanged from the dates the transactions were consummated.

Our energy marketing subsidiary relies on storage and transportation assets that we do not own or control to deliver natural gas and crude oil.

The commodity, storage and transportation portfolios at our energy marketing operations consist of contracts to buy and sell natural gas and crude oil commodities, many of which are settled by physical delivery.

We depend on pipelines and other storage and transportation facilities owned and operated by third parties to deliver these commodities to satisfy contractual commitments. If transportation is disrupted, or if storage capacity is inadequate, including for reasons of force majeure, our ability to fulfill our commitments may be hindered. As a result, we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates.

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.

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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.

Federal and/or State requirements imposing further emission reduction mandates, including limitations on CO_2 emissions, could make some of our electric generating units uneconomical to maintain and operate.

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil-fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. The issue of global climate change is receiving increased attention with a strong focus on CO_2 emissions from power generation facilities and their potential role in climate change. There is considerable debate regarding the public policy approach that the United States should follow to address this issue. Although several bills have been introduced in Congress that would compel CO_2 emission reductions, none have been enacted into law. Future changes in environmental regulations governing these pollutants could make some of our electric generating units more expensive or uneconomical to maintain and operate. In addition, any legal obligation that would require us to substantially reduce our emissions below present levels could require extensive mitigation efforts and, in the case of CO_2 legislation, may raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

Governmental authorities may assess penalties on us if it is determined that we have not complied with environmental laws and regulations.

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines against us. Recent lawsuits by the EPA and various states filed against others within industries in which we operate, highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities in particular.

Our natural gas distribution activities involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our natural gas distribution activities are a variety of hazards and operating risks, such as leaks, explosions and mechanical problems that could cause substantial adverse financial impacts. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations, and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse affect on our financial position and results of operations. For our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damages resulting from these risks could be greater. If we are able to complete the pending Aquila acquisition, our natural gas distribution activities will expand greatly.

Increased risks of regulatory penalties could negatively impact our business.

EPA 2005 increased FERC s civil penalty authority for violation of FERC statutes, rules and orders. FERC can now impose penalties of $1.0 million per violation, per day. Many rules that were historically subject to voluntary compliance are now mandatory and subject to potential civil penalties for violations. If a serious violation did occur, and penalties were imposed by FERC, it could have a material adverse effect on our operations or financial results of operations.

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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 business 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 attempt to sell the plant s power at prevailing 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 for the states in which we operate 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 or pay dividends to our shareholders.

Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

We have multiple defined benefit pension and non-pension postretirement plans that cover a substantial portion of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on actual return on plan assets, changes in interest rates and any changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Therefore, our funding requirements may change and additional contributions could be required in the future.

Increasing costs associated with health care plans may adversely affect our results of operations, financial position or liquidity.

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm also attests to the effectiveness of these controls. During their assessment of these controls, management or our independent auditors may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists.

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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 2007.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 45, was elected Chairman in April 2005 and has been President and Chief Executive Officer and a member of the Board of Directors since 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 18 years of experience with us.

Thomas M. Ohlmacher, age 56, has been the President and Chief Operating Officer of our Non-regulated 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 33 years of experience with us.

Linden R. Evans, age 45, has been President and Chief Operating Officer Utilities since 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 6 years of experience with us.

Steven J. Helmers, age 51, 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 7 years of experience with us.

Maurice T. Klefeker, age 51, has been Senior Vice President Strategic Planning and Development since 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 8 years of experience with us.

James M. Mattern, age 53, 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 20 years of experience with us.

Roxann R. Basham, age 46, has been Vice President Governance and Corporate Secretary since February 2004. Prior to that, she was our Vice President Controller from March 2000 to January 2004. Ms. Basham has a total of 24 years of experience with us.

Kyle D. White, age 48, has been Vice President Corporate Affairs since January 30, 2001 and Vice President Marketing and Regulatory Affairs since July 1998. Mr. White has 25 years of experience with us.

Garner M. Anderson, age 45, has been Vice President, Treasurer and Chief Risk Officer since October 2006. He had served as Vice President and Treasurer since July 2003. Mr. Anderson has 19 years of experience with us, including positions as Director Treasury Services and Risk Manager.

Perry S. Krush, age 48, has been Vice President Controller since December 2004. Mr. Krush has 19 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, 2008, we had 4,911 common shareholders of record and approximately 15,100 beneficial owners, representing all 50 states, the District of Columbia and 10 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 November 2007 meeting, our Board of Directors declared a quarterly dividend of $0.35 per share, equivalent to an annual dividend of $1.40 per share, marking 2008 as the 38th 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 to 1.0, our recourse leverage ratio exceeds 0.65 to 1.00 (or 0.70 to 1.00 for the first year after the Aquila acquisition) 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, 2007, we were in compliance with all covenants, and accordingly, are not currently restricted from paying any 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, 2007		First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share		$ 0.34	$ 0.34	$ 0.34	$ 0.35
Common stock prices					
	High				
High		$ 39.63	$ 42.59	$ 44.48	$ 45.41
Low		$ 35.40	$ 36.86	$ 36.84	$ 40.21

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				
High	$ 40.00	$ 37.52	$ 36.86	$ 37.95
Low	$ 32.92	$ 32.46	$ 33.20	$ 33.38

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UNREGISTERED SECURITIES ISSUED DURING 2007

No unregistered securities were sold during 2007, except as has been previously reported in our periodic and current reports to the SEC.

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, 2007 - October 31, 2007	39 (1)	$ 44.42		
November 1, 2007 - November 30, 2007	356 (1)	$ 40.83		
December 1, 2007 - December 31, 2007	2,586 (2)	$ 43.20		
Total	2,981	$ 42.93		

(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 261 shares acquired by a Rabbi Trust for the Outside Directors Stock Based Compensation Plan, and 2,325 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,	2007	2006	2005	2004	2003
Total Assets (in thousands)	$ 2,472,866	$ 2,244,676	$ 2,120,258	$ 2,029,588	$ 2,044,555
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 2,490,565	$ 2,242,396	$ 1,928,559	$ 1,778,615	$ 1,698,411
Accumulated depreciation and depletion	(667,031)	(596,029)	(518,525)	(465,845)	(395,518)
Capital Expenditures (in thousands)	$ 267,047	$ 308,450	$ 208,856	$ 90,974	$ 116,691
Capitalization (in thousands)					
Long-term debt, net of current maturities	$ 564,372	$ 628,340	$ 670,193	$ 733,581	$ 868,459
Preferred stock equity				7,167	8,143
Common stock equity	969,855	790,041	738,879	728,598	701,604
Total capitalization	$ 1,534,227	$ 1,418,381	$ 1,409,072	$ 1,469,346	$ 1,578,206
Capitalization Ratios					
Long-term debt, net of current maturities	36.8%	44.3%	47.6%	49.9%	55.0%
Preferred stock equity				0.5	0.5
Common stock equity	63.2	55.7	52.4	49.6	44.5
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues (in thousands)	$ 695,914	$ 656,882	$ 613,541	$ 445,543	$ 559,315(1)
Net Income Available for Common (in thousands):					
Utilities	$ 31,633	$ 24,188	$ 20,119	$ 19,209	$ 23,999
Non-regulated energy	74,363(2)	55,372	26,164(2)	40,862	42,961(2)
Corporate expenses and intersegment eliminations	(5,872)	(5,514)	(13,491)	(3,790)	(7,970)
Income from Continuing Operations Before Changes in Accounting Principles	100,124	74,046	32,792	56,281	58,990
Discontinued operations	(1,352)	6,973	628	1,692	7,427
Changes in accounting principles, net of tax					(5,195)
Preferred dividends			(159)	(321)	(258)
	$ 98,772	$ 81,019	$ 33,261	$ 57,652	$ 60,964
Dividends Paid on Common Stock (in thousands)	$ 50,300	$ 43,960	$ 42,053	$ 40,210	$ 37,025
Common Stock Data (in thousands)					
Shares outstanding, average	37,024	33,179	32,765	32,387	30,496
Shares outstanding, average diluted	37,414	33,549	33,288	32,912	31,015
Shares outstanding, end of year	37,796	33,369	33,156	32,478	32,298
Earnings Per Share of Common Stock (in dollars)(3)					
Basic earnings (losses) per average share -					
Continuing operations	$ 2.70	$ 2.23	$ 1.00	$ 1.73	$ 1.93
Discontinued operations	(0.04)	0.21	0.02	0.05	0.24
Change in accounting principle					(0.17)
Total	$ 2.66	$ 2.44	$ 1.02	$ 1.78	$ 2.00
Diluted earnings (losses) per average share -					
Continuing operations	$ 2.68	$ 2.21	$ 0.98	$ 1.71	$ 1.90
Discontinued operations	(0.04)	0.21	0.02	0.05	0.24
Changes in accounting principles					(0.17)
Total	$ 2.64	$ 2.42	$ 1.00	$ 1.76	$ 1.97
Dividends Paid per Share	$ 1.37	$ 1.32	$ 1.28	$ 1.24	$ 1.20

Book Value Per Share, End of Year	$ 25.66	$ 23.68	$ 22.28	$ 22.43	$ 21.72
Return on Average Common Stock Equity (year-end)	11.2%	10.6%	4.5%	8.1%	9.9%

Operating Statistics:

Years ended December 31,	2007	2006	2005	2004	2003
Generating capacity (MW):					
Utility (owned generation)	435	435	435	435	435
Utility (purchased capacity)	50	50	50	50	55
Independent power generation(4)	983	989	1,000	1,004	1,002
Total generating capacity	1,468	1,474	1,485	1,489	1,492
Electric utility sales (MW-hours):					
Retail electric sales	1,678,138	1,632,352	1,582,841	1,509,635	1,536,836
Contracted wholesale sales	652,931	647,444	619,369	614,700	614,888
Wholesale off-system	678,581	942,045	869,161	926,461	773,801
Total utility electric sales	3,009,650	3,221,841	3,071,371	3,050,796	2,925,525
Electric and gas utility sales:					
Electric MW-hours	958,287	919,938	889,210		
Gas sales Dth	4,427,902	4,387,767	4,062,590		
Oil and gas production sold (MMcfe)	14,627	14,414	13,745	12,595	10,843
Oil and gas reserves (MMcfe)	207,806	199,092	169,583	173,417	156,396
Tons of coal sold (thousands of tons)	5,049	4,717	4,702	4,780	4,812
Coal reserves (thousands of tons)	280,000	285,000	290,000	294,000	263,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,743,500	1,598,200	1,427,400	1,226,600	897,850
Crude oil physical sales (Bbls) (5)	8,600	8,800			

Certain items related to 2003 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 to reduce the carrying value of long-lived assets to fair value and record related costs were approximately $2.2 million after-tax in 2007, $33.9 million after-tax in 2005, and $76.2 million after-tax in 2003.

(3) In February 2007, we issued 4.2 million shares of common stock and in May 2003 we issued 4.6 million shares of common stock, which dilutes our earnings per share in subsequent periods.
(4) Includes 40 MW in 2004 and 2003, which have been reported as Discontinued operations.
(5) Represents crude oil 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 Utilities and Non-regulated energy (previously Retail services and Wholesale energy, respectively). We report for our business groups in the following financial segments:

Business Group	**Financial Segment**
Utilities group	Electric utility
	Electric and gas utility
Non-regulated energy group	Oil and gas
	Power generation
	Coal mining
	Energy marketing

Our Utilities business 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 65,100 customers in South Dakota, Wyoming and Montana. Cheyenne Light serves approximately 39,400 electric customers and 33,000 natural gas customers in Cheyenne, Wyoming and vicinity. Our Non-regulated 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 2007. 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 most of the year, reducing demand for fuel used for power generation and heating. Minimal hurricane activity allowed for normal Gulf of Mexico oil and gas production. At year-end 2007, domestic supplies of natural gas in storage were above historical averages.

While the major economic factors affecting energy remained positive in 2007, the political environment changed significantly. Environmental issues took center stage in the U.S. Congress in 2007. Among the topics of emphasis were federally-mandated renewable portfolio standards, carbon taxes, carbon cap-and-trade arrangements, and mandated reductions of greenhouse gas emissions. Although the Congress has not yet enacted any major legislation relative to these environmental issues, it appears increasingly likely in the future. All of these potential legislative actions could have significant macroeconomic consequences. The associated cost increase would cause a dramatic increase in consumers rates for electricity and other energy in the mid- to long-term. State Legislatures, too, were very active on the environmental front, with a total of approximately 31 states now having adopted some form of renewable standard, including some where we operate.

The federal and state regulatory climate in 2007, in a general sense, remained relatively constructive among government, industry and consumer representatives. In the multi-state region surrounding our utility operations, regulators were willing to establish rates based on multi-year considerations, including fuel and other reasonable cost adjustments, justifiable capital expenditures for maintenance and expansion of energy systems, and a response to environmental considerations through demand management and efficiency programs.

Progress in the domestic energy industry in 2007 included continued oil and gas exploration and production activity in the Rocky Mountains, continued planning and construction of liquefied natural gas port facilities, proposals for additional coal-fired and nuclear power plants, planning for additional transmission capacity, and the advancement of renewable energy resources and utilization. Of particular note was the regional expansion of natural gas transportation out of Colorado, with the completion of the second phase of the Rockies Express Pipeline.

The energy industry continues to adjust to change, including the trends of consolidation in the electric and gas utility sectors, along with asset divestitures to restrict or redefine business strategies. The energy market place continues to adjust to 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.

Over the last several years, the corporate structure of many energy companies underwent evaluation and change, in large part due to efforts to create additional shareholder value. A number of companies are contemplating or implementing a realignment of business lines, reflecting a shift in long-term strategies. Some are divesting certain energy properties to focus on core businesses, such as exiting unregulated power production or oil and gas production in favor of more stable utility operations. Others have engaged in mergers and acquisitions with a goal to improve economies of scale and returns to investors. Private equity investors continued to play a role in the changing composition of energy ownership, but to a lesser extent than previous years.

Many industry analysts have identified the need for expanded energy capacity and delivery systems. They foresee an increase in capital investments across a wide spectrum of energy companies. Many electric and gas utilities must replace aging plants and equipment, and regulators appear to be willing to provide acceptable rate treatment for additional utility investment. Oil and gas producers are expected to continue to increase capital spending in response to relatively high prices, particularly for oil. Historically high field service costs, however, have begun to curtail projects as companies more closely examine their economic considerations. In addition, the process for obtaining drilling permits, particularly on public and Native American lands, is getting increasingly more difficult.

In 2007, the domestic coal industry benefited from a positive 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. Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including U.S. allies, advocate reductions in CO_2 and other emissions. Many states now encourage the energy industry to invest in renewable energy resources, such as wind or solar power, or the use of bio-mass as a fuel. In many instances, renewable energy use is mandated by state regulators. Furthermore, in the case of California, rules have established a requirement that future imports of power must come from power plants with lower emission levels than currently associated with conventional coal-fired plants. Such restrictions may 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 small fraction of those produced by power plants built a generation ago. Along with similar technological progress, coal can and likely will remain an important, domestically available, and economical national energy resource that is vital to meet growing energy demand. To that point, the U.S. Department of Energy is beginning to take positive steps toward ensuring the future of coal through research funding for clean coal technologies and methods of carbon capture/sequestration.

Like other U.S. industries, the energy industry is faced with uncertainties looming on the economic horizon. A global credit problem emerged from a proliferation of sub-prime lending. As that issue attracted attention, other credit quality concerns surfaced, creating an international-scale financial crisis, which could likely take years to resolve. Access to debt markets and capital availability are crucial for a robust and capital-intensive energy industry. Another issue facing the U.S. economy is inflation. As energy companies expand, inflation can impair the ability to manage the costs of lengthy construction projects and other factors. Still another uncertainty is a growing probability of a domestic recession. Utility companies generally are less impacted by economic downturns, but a prolonged or severe recession can affect the demand for energy services and the ability of companies to execute capital expansion plans.

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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 and efficiency, the demand for energy is expected to increase steadily over time. To meet that growing demand, the industry is ready to provide capital, resources and innovation to serve customers in cost-effective ways and to achieve returns on investment.

The Company believes that it is well-positioned in this industry setting and able to proceed with its strategic agenda. We also believe that we, along with industry counterparts, are ready to address the challenges discussed in this overview, such as new environmental mandates, renewable portfolio standards, carbon-related taxes or trading systems, credit market conditions, inflation, or other factors that can affect energy demand and supply. In particular, we are sensitive to additional costs that can negatively affect our customers or our profitability. To that end, we intend to work closely with regulators and industry leaders to assure that cost-conscious proposals and solutions are prominent in public policy proceedings.

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of utility operations, including electric and gas distribution systems; fuel assets and services, including oil, natural gas and coal production and marketing operations; and electric generation operations. Our focus on customers whether utility customers or non-regulated generation, fuel or marketing customers provides opportunities to expand our businesses. Our balanced, integrated approach to the energy business is supported by disciplined risk management practices.

The diversity of our operations reduces reliance on any single business to achieve our strategic objectives. Our diversification 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 potentially stronger returns over the long term. We have a strong and stable balance sheet, which is essential given the demands of the market. We possess access to capital, sufficient liquidity, and solid cash flows and earnings. Consequently, we believe our financial foundation is sound and capable of supporting an expansion of operations in both the near and long term.

Related to our long-term strategy, our current emphasis is to expand our core utility operations and their power generation assets, while we provide sufficient growth capital for our non-regulated fuel, generation and energy marketing operations. We currently are evaluating the strategic merits of certain of our non-regulated power generation assets. As a result of that evaluation, we may elect to sell some or all of such assets.

Our long-term strategy focuses on increasing our customer base and providing superior economic and performance value to both utility and non-regulated energy customers. In our utility operations, we seek to grow our existing asset base through construction of new rate-based generation facilities, and by adding new customers through the acquisition of additional utility properties. We intend to maintain our high customer service and reliability standards. In our fuel production operations, we will continue to economically grow and develop our existing inventory of oil and gas reserves, while we strive to maintain our positive relationships with mineral owners, landowners and regulatory authorities. We seek to develop additional markets for our coal production, including the development of additional power plants at our mine site. Our non-regulated power generation business will continue to focus on long-term contractual relationships with key wholesale customers, as well as new customers that will allow us to selectively grow our power generation business, while evaluating the strategic merits of certain of our existing facilities. The expertise of our energy marketing business should allow us to continue to provide profitability through a risk-managed and disciplined approach to producer service, origination, storage, transportation and proprietary marketing strategies.

The following are key elements of our business strategy:

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

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages;

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

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

Proactively integrate alternative and renewable energy into our utility energy supply while remaining mindful of potential customer rate impacts;

Selectively grow our power generation segment by developing assets in targeted Western markets, while evaluating the strategic merits of certain of our existing assets;

Sell a large percentage of our capacity and energy production from our non-regulated power generation projects through mid-and long-term contracts primarily to load-serving utilities in order to secure a stable revenue stream and attractive returns;

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

Build and maintain strong relationships with wholesale power customers;

Efficiently utilize our coal resources through expansion of mine-mouth generation and increased third-party coal sales;

Grow our reserves and increase our production of natural gas and crude oil;

Geographically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, natural gas and crude oil storage and transportation opportunities;

Diligently manage the risks inherent in energy marketing; and

Conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties.

Operate our lines of business as utility and non-regulated energy components. The utility component consists of electric and natural gas products and services. The non-regulated energy component consists of fuel production, mid-stream assets, power production facilities and energy marketing. We partition operations into utility and non-regulated energy business groups to achieve operating efficiencies. In the Utilities group, the integration of customer service, marketing and promotional efforts streamline operating processes and improve productivity. In the non-regulated energy group, the fuel production, generation and marketing segments integrate balanced, yet diverse strategic operations.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For 125 years, we and our predecessor companies have provided strong utility services, based on delivering quality and value to our customers. Our tradition of accomplishment is expected to support efforts to expand our utility operations into other markets, most likely in the Midwest, West and possibly other regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation, system reliability, superior customer service and a relationship-based approach to regulatory matters. The 2005 acquisition of Cheyenne Light and the pending acquisition of certain electric and gas utility assets of Aquila are examples of such expansion efforts. Utility operations also enhance other important business development, including gas transmission pipelines and storage infrastructure, which could promote other non-regulated energy operations. Utility operations can contribute substantially to the stability of our long-term cash flows, earnings and dividend policy.

Complete our proposed acquisition of certain Aquila-owned utility assets and successfully integrate and profitably operate our expanded utility operations. Our pending acquisition of Aquila s five utility properties in four states will significantly expand 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 long-term 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. As of February 29, 2008, we received approvals from regulators in the states of Iowa, Nebraska and Colorado, obtained federal antitrust clearance, and received FERC approval of the Colorado electric property acquisition. On February 12, 2008, a hearing was held by the Kansas Corporation Commission on our joint application with Aquila. All the parties to the Kansas proceeding entered into a settlement which was presented at that hearing. A decision by the Kansas regulators is pending. In addition, another party to the transaction, Great Plains Energy, must obtain approval from regulators in the states of Missouri and Kansas, which are pending.

We will require access to the capital markets to secure capital sufficient to fund our acquisition. We have obtained a $1.0 billion temporary financing arrangement with a termination date of February 5, 2009. In the interim, we intend to obtain permanent financing for the transaction from a variety of sources, including equity, mandatory convertible securities, corporate-level debt or cash from operations or the potential divestiture of certain non-regulated power plant assets. Access to capital markets could be impacted by our ability to maintain our investment grade issuer credit rating. We expect that the acquisition will result in multiple benefits after a period of transition and integration costs. We will strive to integrate our current and acquired utility operations to achieve these anticipated benefits.

Plan, 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 and strategy today, where we invest in and operate 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, the assets 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.

Examples of our progress include the recent start-up of commercial operations at Wygen II, and the ongoing permitting and development of Wygen III. In 2007, we submitted to regulators an Integrated Resource Plan and applied for an Industrial Siting Permit and a Certificate of Public Convenience and Necessity for Wygen III. The Industrial Siting Permit was obtained in January 2008. The Certificate is pending with hearings scheduled to begin during March 2008. Once the Certificate is obtained, we expect to commence construction of Wygen III in the spring of 2008.

Proactively integrate alternative and renewable energy into our utility energy supply while remaining mindful of potential customer rate impacts. The energy and utility industries are faced with a tremendous amount of uncertainty related to the potential impact of legislation intended to decrease greenhouse gas emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted and others are considering some form of mandatory renewable energy standard requiring utilities to meet certain thresholds for the use of renewable energy. Additionally, many states have either enacted or are considering legislation setting greenhouse gas emissions reduction targets. Federal legislation for both renewable energy standards and greenhouse gas emission reductions are also under consideration. Any significant mandate for renewable energy supplies or greenhouse gas emission reductions would likely increase prices for electricity and natural gas considerably.

The Company s strategy related to renewable energy standards and greenhouse gas emission reductions is customer-centered and attempts to balance our customers rate concerns with environmental considerations. As a regulated public utility, we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. Absent any specific renewable energy standard in South Dakota and Wyoming, our current strategy is to prudently incorporate renewable energy into our resource supply, while seeking to minimize rate increases for our utility customers. We have executed a 20-year purchase power agreement commencing in September 2008 for 30 MW of wind energy resources to be located in Cheyenne, Wyoming. We are exploring other potential biomass and wind energy projects, and are evaluating other potential wind generator sites, including sites located near our utility service territories.

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Using reasonable assumptions, we have carefully evaluated our coal-fired generating facilities and the potential future economic impact of a carbon tax or cap and trade regime intended to reduce CO_2 emissions. Based on current assumptions, we believe it is in our utility customers long-term interest to construct new mine-mouth, coal-fired generating facilities, such as our recently completed Wygen II generation facility and our proposed Wygen III generation facility. We are also evaluating alternative coal-fired generation technologies, including IGCC and carbon capture and sequestration, though both appear cost prohibitive in the near term.

Selectively grow our power generation segment by developing assets in targeted Western markets, while evaluating the strategic merits of certain of our existing assets. We aim to continue developing and operating 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 to pursue small-scale build-outs to serve incremental growth, and improve the likelihood of receiving approvals for permitting and siting. In 2007, we began construction of another independent power plant to provide capacity and energy to Public Service Company of New Mexico under a 20-year tolling arrangement. That plant is expected to be in commercial service in June 2008.

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, Fountain Valley and Harbor sites in particular provide further opportunities for significant expansion of our gas- and coal-fired generating capacity over the next several years.

In 2007, we initiated an evaluation of the merits of divesting certain power generation assets. That strategic review is ongoing as of February 29, 2008. While much of our recent power plant development has been for regulated utilities, we may continue to expand our non-regulated power generation business with select projects that are consistent with our overall strategies.

Sell a large percentage of our capacity and energy production from our non-regulated power generation projects through mid- and long-term contracts primarily to load-serving utilities in order to secure a stable revenue stream and attractive returns. The majority of our energy and capacity is provided under mid- and long-term contracts. By doing so, 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-reviewed or -approved contracts primarily to load-serving utilities.

The first of our long-term power contracts expires in 2008, and nearly all expire before 2014. These contract 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 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. They are also located to provide advantageous, 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 accordingly.

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. We intend to utilize a competitive power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream. Competitive 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. In addition, we typically operate our plants with high levels of availability, as compared to national standards. We aggressively manage each of these factors with the goal of achieving low production costs.

A 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 for many other utilities.

Build and maintain strong relationships with wholesale power customers. We strive to build strong relationships with utilities, municipalities and other wholesale customers and believe we will continue to be a primary provider of electricity to wholesale utility customers. 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.

Efficiently utilize our coal resources through expansion of mine-mouth generation and increased third-party 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. Recently, we renegotiated a contract to provide coal for the Dave Johnston power plant in Wyoming and extended the term through 2011.

Grow our reserves and increase our 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:

Increase our reserves primarily by focusing our operations on lower-risk development and exploratory drilling;

Participate on a non-operated basis through taking working interests with other similar scale operators to provide exposure to additional producing basins;

Add reserves and increase production by focusing primarily on various 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;

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; and

Enhance our oil and gas production activities with the construction or acquisition of mid-stream gathering, compression and treating systems in a manner that maximizes the economic value of our operations.

Geographically expand our energy marketing operations including producer and end-use origination services and, as warranted by market conditions, 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 crude oil and to capitalize on market volatility by employing storage, transportation and proprietary trading strategies. 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 origination services, 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.

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. All 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.

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.

Utilities

Electric Utility

Business at our electric utility, Black Hills Power, remained strong in 2007. We believe that Black Hills Power will produce modest growth in revenue, and absent unplanned plant outages, 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 to two percent, with the system demand forecasted to increase at a rate of one to 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.

In 2008, we plan to begin construction of Wygen III, a 100 MW coal-fired power plant to be located at our Neil Simpson Complex. We have received the required air permit and industrial siting permit, with the last regulatory step, obtaining a Certificate of Public Convenience and Necessity from the State of Wyoming, set for hearing on March 8, 2008. Upon obtaining this permit, we would commence construction. We anticipate that Black Hills Power will have 55 MW of the facilities capacity and are considering third-party investors to own the remaining 45 MW.

Electric and Gas Utility

We acquired Cheyenne Light in January 2005. On January 1, 2008, Wygen II, a 95 MW baseload coal-fired power plant commenced commercial service as a rate base asset to serve Cheyenne Light. The plant cost approximately $182 million, including interim financing costs during construction. Effective January 1, 2008, a regulatory approved agreement between the affiliates gives Cheyenne Light the ability to sell its surplus energy to Black Hills Power. In addition, we entered into a 20 year contract to purchase up to 30 MW of renewable wind power, beginning in September 2008. The energy from this contract can be utilized by both Cheyenne Light and Black Hills Power. 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 Utilities group. Through the transaction, we will acquire the assets of Aquila s regulated electric utility in Colorado and their regulated gas utilities in Colorado, Kansas, Nebraska and Iowa. The transaction would add approximately 612,000 new utility customers (92,000 electric customers and 520,000 gas customers) to our current customer base. The regulatory approval process is progressing. As of February 29, 2008, approvals have been received from the states of Iowa, Nebraska and Colorado; federal antitrust clearance was obtained under the Hart-Scott-Rodino Act; and FERC has approved of the Colorado Electric acquisition. On February 12, 2008, a hearing was held by the Kansas Corporation Commission on our joint application with Aquila. All the parties to the Kansas proceeding entered into a settlement which was presented at that hearing. A decision by the Kansas regulators is pending. In addition, our purchase of these utility assets is cross-contingent with the merger of Great Plains Energy and Aquila, whose remaining assets would be in the state of Missouri. Great Plains Energy must obtain regulatory approvals in the states of Missouri and Kansas, which are pending.

To prepare for the acquisition, we have been expensing certain temporary transition and integration costs as they have occurred, amounting to approximately $4.8 million after tax, for the year ended December 31, 2007. In addition, we have capitalized certain costs relating to the acquisition, amounting to approximately $19.1 million, as of December 31, 2007. The transaction is expected to close in the second quarter of 2008. The Company expects the acquisition to be dilutive to earnings in the first full year of operations. The purchase price of $940 million is expected to be financed through a combination of equity, corporate level debt, mandatory convertible securities, and internally generated cash, which could include cash proceeds from the potential divestiture of certain non-regulated power plant assets.

Non-regulated Energy Group

Power Generation

Earnings from our Power Generation segment in 2008 will benefit from commercial operation of the Valencia plant beginning in the summer of 2008. This will be partially offset by a decrease in earnings and cash flows associated with our receipt from SCE of contract termination payments for the Harbor facility, which will be completed in October 2008.

We are conducting a strategic review of our assets within this segment, which may result in the divestiture of certain of our non-regulated power generation assets. Such divestiture would, of course, result in a reduction of future earnings and cash flows, offset initially by any potential gain on sale and ultimately by alternative use of the sale proceeds.

Coal Mining

Production from the coal mining segment is expected to primarily serve mine-mouth generation plants and select regional customers with long-term fuel needs. Increased demand will come from additional mine-mouth generation either currently being constructed or in various stages of development. A contract to provide coal to PacifiCorp s Dave Johnston power plant was renegotiated in late 2007. Beginning in 2008, it provides for the sale of up to 1.8 million tons of coal annually through 2011. Previous coal sales to the plant ranged from 0.3 million tons to 1.3 million tons during previous contract years 2001 through 2007. Deliveries to the Wygen II power plant began in late 2007. The demand from the new Dave Johnston and Wygen II contracts is expected to result in a production increase of approximately 1.0 million tons annually. Total annual production is estimated to be approximately 6.0 million tons in 2008, compared to 5.0 million tons in 2007 and 4.7 million tons in 2006 and 2005.

We expect lower earnings from this segment in 2008, as higher revenues from production and coal price increases is offset by higher operating expenses. Operating cost increases will be driven by higher labor and equipment costs as overburden ratios and production levels increase. Non-operating income will also decrease as a result of recapitalizing our coal mining subsidiary.

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 2 to 4 percent. Recent results, which have not attained expected performance, reflected weakened economic conditions caused by rapidly increasing capital costs and operating expenses. Consequently, we elected to reduce our drilling program in 2007.

As economic conditions merit, we may elect to increase our drilling and production activity. Near term growth is expected to come from development of our 2006 acquisitions in the Piceance Basin and the ongoing development of the San Juan, Powder River and Williston Basins. We expect to deploy approximately $94.2 million of capital in 2008 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, Piceance and Powder River Basins. In addition, we may invest in mid-stream assets, such as gathering, compression and treating systems.

Energy Marketing

We expect lower earnings from this segment in 2008, as 2007 earnings were strong due to unusually favorable natural gas market conditions. A new natural gas pipeline providing expanded transportation services out of the Rocky Mountain region may affect market conditions and the opportunity to effectively exploit certain regional price basis differentials. 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.

Results of Operations

Executive Summary

Results for the year 2007 reflect solid utility performance, strong energy marketing results and improved power generation and coal mining performance, while the oil and gas segment results were similar to 2006.

Earnings for the utilities increased 31 percent over the prior year. A rate increase for Black Hills Power s South Dakota service territory went into effect January 1, 2007. Results for Cheyenne Light were impacted by increased AFUDC income attributable to the 95 MW coal-fired Wygen II plant which was placed in commercial service January 1, 2008. In November 2007, the WPSC approved a new rate structure for Cheyenne Light and included the Wygen II plant in the rate base effective January 1, 2008.

Strong earnings from energy marketing are primarily attributable to a $30.7 million increase in realized gas marketing margins. Earnings benefited from favorable natural gas market conditions that prevailed throughout 2007. Daily average physical gas volumes marketed increased 9 percent over 2006. This segment also reflects oil marketing operations in the Rocky Mountain region for the full year in 2007.

Power generation improved earnings for 2007 as the Las Vegas plants were returned to normal operations after extensive repairs and maintenance in 2006 for scheduled and unscheduled outages. Earnings were also impacted by a $1.8 million after-tax impairment charge for the Ontario plant and $0.4 million after-tax for a goodwill impairment. Lower investment partnership earnings were primarily a result of a partnership impairment charge for the Glenns Ferry and Rupert power plants in which we hold a 50 percent interest. The impairments reduced our equity in earnings of unconsolidated subsidiaries by approximately $2.7 million after-tax.

Oil and gas segment earnings were similar to the previous year. A 7 percent increase in revenues was offset by increased operating, depletion and interest costs.

Coal mining earnings increased due to higher average prices received and increased tons of coal sold partially offset by increased overburden expense and higher mineral taxes and royalties due to increased revenues and tons sold.

Overview

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

	2007	2006	2005
Revenue:			
Utilities	$ 301,514	$ 323,003	$ 297,681
Non-regulated energy	394,400	333,833	315,089
Corporate		46	771
	$ 695,914	$ 656,882	$ 613,541

	2007	2006	2005
Income (loss) from continuing operations:			
Utilities	$ 31,633	$ 24,188	$ 20,119
Non-regulated energy	74,363	55,372	26,164
Corporate	(5,872)	(5,514)	(13,491)
	$ 100,124	$ 74,046	$ 32,792

The Corporate results represent 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 Consolidated Financial Statements from the date of acquisition.

Discontinued operations in 2007, 2006 and 2005 represents the operations and gain on sale of our crude oil marketing and transportation business, sold in March 2006. In addition to the Houston, Texas based crude oil marketing and transportation operations, the 2005 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 have been restated to reflect the operations discontinued.

2007 Compared to 2006

Consolidated income from continuing operations for 2007 was $100.1 million, compared to $74.0 million in 2006, or $2.68 per share in 2007, compared to $2.21 per share in 2006. Loss from discontinued operations was $1.4 million, or $0.04 per share, compared to income of $7.0 million, or $0.21 per share in 2006. Results for 2006 include the $8.9 million gain on the sale of the operating assets of the crude oil marketing and transportation business. Return on average common stock equity in 2007 and 2006 was 11.2 percent and 10.6 percent, respectively.

The Utilities group income from continuing operations increased $7.4 million in 2007 compared to 2006. Earnings from continuing operations from the electric utility increased $6.2 million primarily due to an increase in retail rates. Earnings from continuing operations from the electric and gas utility increased $1.2 million primarily due to AFUDC and associated tax benefits related to the construction of Wygen II.

The Non-regulated energy group s income from continuing operations increased $19.0 million in 2007, compared to 2006, primarily due to increased earnings from energy marketing of $16.9 million and power generation of $1.5 million.

Unallocated corporate costs for 2007 increased $0.4 million after-tax, compared to 2006. The increase is primarily due to increased acquisition and integration costs for the Aquila acquisition offset by lower interest expense which was allocated down to the subsidiary level in 2007.

Consolidated revenues for 2007 were $39.0 million higher than 2006 due to increased revenues from all operating segments, other than the electric and gas utility which had lower revenues primarily due to lower ECA and GCA pass-through cost recovery rate adjustments. We consider gross margin to be a more useful performance measure for the electric and gas utility as fluctuations in cost of electricity and gas flow through to revenues through cost recovery rate adjustments.

Consolidated operating expenses for 2007 increased $12.2 million compared to 2006. Increased operating expenses reflect a $3.3 million impairment charge at our power generation segment, increased compensation costs at the energy marketing segment, a $5.6 million increase in depreciation, depletion and amortization expense, primarily due to increased depletion at the oil and gas segment, and a $5.1 million increase in operations and maintenance expense. The increased expenses were partially offset by a $27.6 million decrease in fuel and purchased power primarily due to cost recovery adjustments at the electric and gas utility. The increase in operations and maintenance expense was partially offset by the 2007 receipt of $2.5 million of insurance proceeds as a reimbursement for repair costs incurred in 2006 on the Las Vegas II plant.

Income from continuing operations was also impacted by a $10.1 million decrease in interest expense primarily due to the reduction of debt, using in part, proceeds from the issuance and sale of common stock, and the effect of interest capitalization during ongoing construction and development.

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 crude oil 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.

Income from continuing operations for our Utilities group 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 primarily due to lower write-offs for bad debt and, AFUDC and related tax effects, related to the Wygen II plant.

The Non-regulated 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. Earnings at the power generation segment increased due primarily to a $52.2 million impairment charge in 2005.

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, depletion and amortization 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 in 2006.

A discussion of operating results from our business segments follows.

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2005 information has been revised to remove information related to operations that were discontinued.

Utilities

Electric Utility

	2007 (in thousands)	2006	2005
Revenue	$ 199,701	$ 193,166	$ 189,005
Operating expenses	152,187	153,164	152,961
Operating income	$ 47,514	$ 40,002	$ 36,044
Income from continuing operations and net income	$ 24,896	$ 18,724	$ 18,005

The following tables provide certain electric utility operating statistics:

Electric Revenue
(in thousands)

Customer Base	2007	Percentage Change	2006	Percentage Change	2005
Commercial	$ 55,991	13%	$ 49,756	1%	$ 49,185
Residential	45,657	13	40,491	3	39,348
Industrial	21,974	6	20,694	4	19,982
Municipal sales	2,697	12	2,401	6	2,268
Total retail sales	126,319	11	113,342	2	110,783
Contract wholesale	25,240	2	24,705	6	23,384
Wholesale off-system	35,210	(17)	42,489	(11)	47,647
Total electric sales	186,769	3	180,536	(1)	181,814
Other revenue	12,932	2	12,630	76	7,191
Total revenue	$ 199,701	3%	$ 193,166	2%	$ 189,005

Megawatt-Hours Sold

Customer Base	2007	Percentage Change	2006	Percentage Change	2005
Commercial	690,702	4%	667,220	2%	655,076
Residential	518,148	4	499,152	4	480,053
Industrial	434,627		433,019	4	417,628
Municipal sales	34,661	5	32,961	10	30,084
Total retail sales	1,678,138	3	1,632,352	3	1,582,841
Contract wholesale	652,931	1	647,444	5	619,369
Wholesale off-system	678,581	(28)	942,045	8	869,161
Total electric sales	3,009,650	(7)%	3,221,841	5%	3,071,371

We established a new summer peak load of 430 MW in July 2007 and a new winter peak load of 361 MW in February 2007. We own 435 MW of electric utility generating capacity and purchase an additional 50 MW under a long-term agreement expiring in 2023.

	2007	2006	2005
Regulated power plant fleet availability:			
Coal-fired plants	95.3%	95.5%	93.3%
Other plants	99.6%	98.7%	99.3%
Total availability	97.4%	97.1%	96.3%

Resources	2007	Percentage Change	2006	Percentage Change	2005
MW-hours generated:					
Coal	1,758,280	2%	1,729,636	%	1,728,823
Gas	90,618	67	54,299	46	37,239
	1,848,898	4	1,783,935	1	1,766,062
MW-hours purchased	1,279,005	(18)	1,553,024	11	1,399,212
Total resources	3,127,903	(6)%	3,336,959	5%	3,165,274

	2007	2006	2005
Heating and cooling degree days:			
Actual			
Heating degree days	6,627	6,472	6,488
Cooling degree days	1,033	931	830
Variance from normal			
Heating degree days	(7)%	(10)%	(10)%
Cooling degree days	74%	56%	39%

2007 Compared to 2006

Income from continuing operations increased 33 percent primarily due to:

Retail sales revenues increased 11 percent due to increased rates that went into effect January 1, 2007 and a 3 percent increase in MWh sales;

Purchased power costs decreased 9 percent due to an 18 percent decrease in MWh purchased, partially offset by a 10 percent increase in the price per MWh;

Margins from wholesale off-system sales increased 7 percent; and

Lower property tax due to lower assessed property valuations.

Partially offsetting the increases to earnings was the following:

Fuel expense increased 23 percent due to increased coal prices and the use of higher cost gas generation to meet demand requirements.

2006 Compared to 2005

Income from continuing operations increased 4 percent primarily due to:

Retail sales increased 2 percent and contract wholesale sales increased 6 percent;

Purchased power costs decreased primarily due to a 12 percent lower average costs per Mwh, partially offset by an 11 percent increase in Mwh purchased; and

Decreased power marketing legal costs relative to costs incurred in 2005.

Partially offsetting the earnings increases were the following:

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 MWh sold;

Increased fuel costs 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;

Increased repairs and maintenance costs for the Wyodak plant; and

A higher effective tax rate due to the recording in 2005 of a deferred tax benefit adjustment of $1.9 million

Rate Increase Settlement. In December 2006, we received an order from the SDPUC, effective January 1, 2007, approving a 7.8 percent increase in retail rates and the addition of tariff provisions for automatic cost adjustments. The cost adjustments require the electric utility to absorb a portion of power cost increases partially depending on earnings from certain short-term wholesale sales of electricity. Absent certain conditions, the order also restricts 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 90 percent of the electric utility s total retail revenues.

Electric and Gas Utility

	2007 (in thousands)	2006	January 21, 2005 to December 31, 2005
Revenue	$ 103,710	$ 132,189	$ 110,875
Purchased gas and electricity	76,513	104,922	89,642
Gross margin	27,197	27,267	21,233
Operating expenses	21,399	21,313	18,180
Operating income	$ 5,798	$ 5,954	$ 3,053
Income from continuing operations and net income	$ 6,737	$ 5,464	$ 2,114

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

Electric Margins
(in thousands)

Customer Base	2007	2006	January 21, 2005 to December 31, 2005
Commercial	$ 7,537	$ 7,100	$ 5,773
Residential	8,721	8,599	6,915
Industrial	336	347	437
Municipal	576	562	416
Total electric	17,170	16,608	13,541
Other	209	590	553
Total margins	$ 17,379	$ 17,198	$ 14,094

Gas Margins
(in thousands)

Customer Base	2007	2006	January 21, 2005 to December 31, 2005
Commercial	$ 2,268	$ 2,258	$ 1,430
Residential	6,408	6,389	4,288
Industrial	436	495	394
Total gas	9,112	9,142	6,112
Other	706	927	1,027
Total margins	$ 9,818	$ 10,069	$ 7,139

	2007	2006	January 21, 2005 to December 31, 2005
Electric sales MWh	958,287	919,938	877,798
Gas sales - Dth	4,427,902	4,387,767	4,062,590

	2007	2006	2005
Heating and cooling degree days:			
Actual			
Heating degree days	6,964	6,789	6,622
Cooling degree days	536	486	443
Variance from normal			
Heating degree days	(6)%	(8)%	(10)%
Cooling degree days	96%	78%	62%

2007 Compared to 2006

Gross margins for 2007 were similar to the prior year. We consider gross margin to be a more useful performance measure as fluctuations in cost of electricity and gas flow through to revenues through cost recovery rate adjustments. Income from continuing operations increased 23 percent due to the following:

A $0.7 million decrease in depreciation expense due to lower rates as the result of a depreciation study;

A $1.0 million decrease in the write-off of uncollectible accounts; and

A lower effective income tax rate due to a $0.3 million tax credit and permanent differences related to AFUDC on the Wygen II power plant.

These items were partially offset by:

Increased administrative expense for rate case costs and professional fees; and

A $1.5 million increase in interest expense due to increased borrowings, net of the capitalized interest component of AFUDC.

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

Income from continuing operations was $5.5 million in 2006 compared to $2.1 million in 2005 due to the following:

Gross margin increased 28 percent primarily due to an increase in base rates, a 5 percent increase in electric demand and an 8 percent increase in gas demand;

A full year of operations in 2006 as compared to 2005; and

Increased income from AFUDC associated with the construction of the Wygen II power plant.

Partially offsetting the earnings increases was the following:

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

2008 Rate Increase

In November 2007, the WPSC approved general rate increases of $6.7 million for electric rates and $4.4 million for natural gas rates to provide for increased costs of providing service. The allowed rate of return on equity is 10.9 percent based on a capital structure that is 54 percent equity and 46 percent debt. In addition, the electric rate increase includes placing the 95 megawatt, coal-fired Wygen II power plant into rate base. The WPSC also approved a new pass-through mechanism for Cheyenne Light s electric business. For calendar years beginning in 2008, the annual increase or decrease for transmission, fuel, and purchased power costs is passed on to customers, subject to a $1.0 million threshold. Under its tariff, Cheyenne Light collects or refunds 95 percent of the increase or decrease that is in excess of the $1.0 million threshold. For changes in these costs that are less than the $1.0 million annual threshold, Cheyenne Light absorbs the increase and likewise retains the savings. The new rates and tariffs were effective January 1, 2008.

Non-regulated Energy Group

Oil and Gas

Oil and gas operating results were as follows:

	2007 (in thousands)	2006	2005
Revenue	$ 101,522	$ 95,078	$ 87,549
Operating expenses	76,085	68,990	55,944
Operating income	$ 25,437	$ 26,088	$ 31,605
Income from continuing operations	$ 12,706	$ 12,736	$ 17,905

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

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

	2007	2006	2005
Bbls of oil sold	409,040	401,440	395,550
Mcf of natural gas sold	12,172,400	12,005,600	11,372,000
Mcf equivalent sales	14,626,640	14,414,240	13,745,300

	Average Price Received*		
	2007	2006	2005
Gas/Mcf**	$ 6.19	$ 6.11	$ 6.36
Oil/Bbl	$ 60.29	$ 50.75	$ 35.99

* Net of hedge settlement gains/losses
** Exclusive of gas liquids

	Depletion		
	2007	2006	2005
Depletion expense/Mcfe*	$ 2.21	$ 1.94	$ 1.54

* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented.

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The following is a summary of annual average operating expenses per Mcfe at December 31:

	2007			2006			2005		
	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total
New Mexico	$ 1.04	$ 0.31	$ 1.35	$ 1.11	$ 0.27	$ 1.38	$ 0.42	$ 0.65	$ 1.07
Colorado	0.95	0.79	1.74	1.25	0.49	1.74			
Wyoming	1.19		1.19	1.15		1.15	0.95		0.95
All other properties	0.71	0.17	0.88	0.73	0.15	0.88	0.72	0.06	0.78
Total LOE	$ 0.98	$ 0.23	$ 1.21	$ 1.01	$ 0.18	$ 1.19	$ 0.69	$ 0.24	$ 0.93

At the East Blanco Field in New Mexico and our Piceance Basin assets in Colorado, we own and operate gas gathering systems, including associated compression and treating facilities.

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

	2007	2006	2005
Bbls of oil (in thousands)	5,807	5,723	6,835
MMcf of natural gas	172,964	164,754	128,573
Total MMcf equivalents	207,806	199,092	169,583

Reserves are based on reports prepared by Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm in 2007 and Ralph E. Davis Associates, Inc. in 2006 and 2005. 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 current estimate takes into account 2007 production of approximately 14.2 Bcfe, additions from extensions and discoveries of 23.6 Bcfe and revisions to previous estimates of (0.7) Bcfe.

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

	2007		2006		2005	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 95.98	$ 6.80	$ 61.05	$ 5.52	$ 61.04	$ 11.23
Year-end prices (average well-head)	$ 83.23	$ 5.88	$ 52.06	$ 5.34	$ 58.52	$ 9.06

2007 Compared to 2006

Income from continuing operations was comparable to the prior year.

Revenues from oil and gas sales increased 7 percent due to a 2 percent increase in oil volumes at average prices received that were 19 percent higher than prior year and increased gas sales of 1 percent, at a 1 percent higher average gas price received;

Operations and maintenance costs increased 8 percent due to increases in the number of wells and higher industry costs for services and equipment;

General and administrative costs increased 15 percent primarily due to higher corporate allocations and increased labor costs resulting from staffing increases to support development of 2006 acquisitions;

Depletion per Mcfe increased 14 percent primarily due to increases in current year finding costs and forecasted future development costs and higher industry-wide cost increases; and

Interest expense increased 26 percent due to carrying a full year of Piceance Basin acquisition debt and increased borrowings to fund drilling and exploration activity.

2006 Compared to 2005

Income from continuing operations decreased 29 percent due to the following:

Increased LOE of 33 percent primarily due to generally higher field service costs experienced industry-wide and San Juan compression costs, the East Blanco amine plant costs and operating costs associated with compression and gas treatment for the Piceance Basin properties;

A 26 percent increase in the depletion rate, which reflects higher industry-wide drilling and completion costs that significantly increased estimated future development costs in addition to increased costs from acquisitions and lower reserve estimates; and

Increased federal royalties as a result of expiring royalty relief on stripper wells.

Partially offsetting the earnings decreases was the following:

Revenues from oil and gas increased 9 percent due to a 6 percent increase in gas volumes sold due to increased production from recently completed wells and property acquisitions and a 2 percent increase in oil volumes due to increased drilling activity in the Finn-Shurley field at a 41 percent increase in average price received.

On March 17, 2006, we acquired certain oil and gas assets of Koch Exploration Company, LLC. The assets included 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.

Additional information on our Oil and Gas operations can be found in Note 22 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:

	2007 (in thousands)	2006	2005
Revenue	$ 159,734	$ 154,985	$ 158,399
Operating expenses	103,302*	96,168	160,553*
Operating income (loss)	$ 56,432	$ 58,817	$ (2,154)
Income (loss) from continuing operations	$ 21,372	$ 19,901	$ (12,524)

* Operating expenses in 2007 includes a $3.3 million impairment of long-lived assets and the recording of related costs and 2005 includes 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:

	2007	2006	2005
Independent power capacity:			
MW of independent power capacity in service	983	989	1,000
Contracted fleet plant availability:			
Gas-fired plants	97.6%	92.7%	98.0%
Coal-fired plants	94.4%	95.4%	95.3%
Total	97.3%	93.4%	96.8%

2007 Compared to 2006

Income from continuing operations increased $1.5 million due to the following:

Increased earnings from Las Vegas II due to a full year of operations as compared to 2006 in which the plant incurred outages. The increased earnings were partially offset by increased variable costs due to the higher run times. Insurance proceeds of approximately $2.5 million were received as a reimbursement for the 2006 plant repairs and reduced 2007 operation and maintenance costs; and

Decreased interest expense due to debt reductions and lower interest rates.

Partially offsetting the earnings increase were the following:

Decreased earnings from Las Vegas I due to increased fuel prices and increased variable operations and maintenance costs relative to 2006 due to the 2006 plant outage; and

Decreased earnings of approximately $1.8 million after-tax due to the impairment of the Ontario plant; and

Decreased equity earnings of unconsolidated subsidiaries of approximately $2.1 million after-tax due to the partnership impairment charge for the Glenns Ferry and Rupert power plants in which we hold a 50 percent interest.

2006 Compared to 2005

Income from continuing operations increased $32.4 million primarily due to the following:

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;

Lower variable operating costs at the Las Vegas I and Las Vegas II facilities due to scheduled and unscheduled outages;

Operating expense in 2005 includes a $50.3 million impairment charge on the Las Vegas I power plant; a $1.9 million impairment of goodwill related to certain power fund investments and a $1.6 million charge related to a fuel contract termination; and

The recording in 2005 of a $2.8 million charge for a tax adjustment.

Partially offsetting the earnings increase were the following:

Increased repairs and maintenance expense related to the 2006 Las Vegas II power plant outages, net of $3.9 million of related insurance proceeds received in 2006;

An $8.0 million after-tax decrease in earnings from certain power fund investments; and

Increased interest expense due to higher interest rates.

Plant availability of our contracted fleet in 2005 and 2006 was affected by the planned maintenance at Las Vegas I and unplanned outages at Las Vegas II. The 2006 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.

Coal Mining

Coal mining results were as follows:

	2007	2006	2005
	(in thousands)		
Revenue	$ 42,488	$ 36,282	$ 34,277
Operating expenses	36,311	29,366	26,385
Operating income	$ 6,177	$ 6,916	$ 7,892
Income from continuing operations	$ 6,107	$ 5,877	$ 6,947

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

(thousands of tons)	2007	2006	2005
Tons of coal sold	5,049	4,717	4,702
Coal reserves	280,000	285,000	290,000

2007 Compared to 2006

Income from continuing operations increased 4 percent due to the following:

A 17 percent increase in revenues primarily due to increases in coal pricing, sales in December 2007 to the Wygen II plant for test power, which was placed into commercial service January 1, 2008, and lower revenues in 2006 due to scheduled and unscheduled outages at the Wyodak plant.

Partially offsetting the increased revenues and earnings were the following:

Increased overburden removal costs due to a 19 percent increase in cubic yards moved;

Increased royalty expense primarily due to the increase in revenues; and

Increased mining taxes primarily related to the increase in revenues and tons.

2006 Compared to 2005

Income from continuing operations decreased 15 percent due to the following:

Increased overburden expense due to a change in accounting rules requiring overburden removal to be expensed as incurred;

Higher depreciation expense; and

Higher mineral taxes primarily resulting from increased production and severance taxes due to State of Wyoming audit adjustments.

Partially offsetting the earnings decrease were the following:

Increased revenues of 6 percent primarily due to higher average prices received; and

Increased train load-out sales, although these were substantially offset by decreased sales to the Wyodak power plant due to scheduled and unscheduled outages.

Energy Marketing

Our energy marketing company produced the following results:

	2007	2006	2005
	(in thousands)		
Revenue -			
Realized gas marketing gross margin	$ 84,823	$ 54,088	$ 32,656
Unrealized gas marketing gross margin	468	(6,546)	5,066
Realized oil marketing gross margin	4,146	2,847	
Unrealized oil marketing gross margin	4,399	842	
	93,836	51,231	37,722
Operating expenses	42,067	27,223	18,524
Operating income	$ 51,769	$ 24,008	$ 19,198
Income from continuing operations	$ 34,178	$ 17,322	$ 13,836

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

	2007	2006	2005
Natural gas average daily physical sales MMBtu	1,743,500	1,598,200	1,427,400
Crude oil average daily physical sales Bbls	8,600	8,800	

2007 Compared to 2006

Income from continuing operations increased $16.9 million due to the following:

Realized gross margins from gas marketing increased $30.7 million over the prior year and physical gas volumes marketed increased 9 percent;

A full year of margins from oil marketing operations, which began in May 2006;

Gas marketing unrealized mark-to-market gains were $7.0 million higher; and

Lower professional fees as compared to cost incurred in 2006 related to litigation costs.

Partially offsetting the earnings increase was the following:

Increased tax expense for higher estimated occupation taxes; and

Increased compensation costs related to higher realized marketing margins.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Non-regulated energy group, the Company identified possible instances of noncompliance with regulatory requirements applicable to those activities. The Company has notified the staff of FERC of its findings. The Company has also evaluated recent public announcements of civil penalties ranging from $0.3 million to $7.0 million that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on the Company. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, the final resolution of these matters could have a material impact on the consolidated net income of any particular period, but is not expected to have a material impact upon the Company s overall consolidated financial position.

2006 Compared to 2005

Income from continuing operations increased $3.5 million due to the following:

Realized gross margins from gas marketing increased $21.4 million over the prior year and physical gas volumes marketed increased 12 percent;

Additional margins from oil marketing operations beginning in May 2006; and

Lower professional fees as compared to cost incurred in 2005 related to litigation involving class action lawsuits alleging false reporting of natural gas price and volume information (See Note 18).

Partially offsetting the earnings increase was the following:

Gas marketing unrealized mark-to-market losses were $11.6 million higher;

Increased compensation costs related to higher realized marketing margins; and

Increased bad debt provision.

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.

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.)

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 September 2007, the Company assessed the recoverability of the carrying value of the Ontario power plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. In addition, $1.4 million has been accrued for a contract termination payment and other related costs.

During December 2007, the Company recorded a $0.6 million pre-tax impairment of goodwill related to the anticipated inability to recover our investment in the Glenns Ferry and Rupert power plants. These plants are held in limited partnerships in which we hold a 50 percent interest and are accounted for under the equity method. The partnerships impaired the associated long-lived assets during 2007.

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.

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, 2007, 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 can provide no assurance that these assumptions will not differ significantly 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 oil and gas 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, since 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. The net book value of our oil and gas properties is 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 annually 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 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 segment to fix the price received for anticipated future production and for interest rate swaps we enter into to convert a portion of our variable rate debt, or associated variable rate interest payments, 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.

Our pension plan assets are held in trust and primarily consist of equity and fixed income investments. Target long-term investment allocations consist of 75 percent equities and 25 percent fixed income securities. 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. We do not pre-fund our non-qualified pension plans or our other postretirement benefit plans.

Change in Assumption (in thousands)	Impact on December 31, 2007 Accumulated Postretirement Benefit Obligation		Impact on 2007 Service and Interest Cost	
Increase 1 percent	$	2,631	$	330
Decrease 1 percent	$	(2,082)	$	(252)

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:

Percentage

Financial Position Summary	2007 (in thousands)	2006	Change
Cash and cash equivalents*	$ 81,255	$ 37,530	116.5%
Short-term debt	180,183	162,606	10.8%
Long-term debt	564,372	628,340	(10.2)%
Stockholders equity	969,855	790,041	22.8%
Ratios			
Long-term debt ratio	36.8%	44.3%	(16.9)%
Total debt ratio	43.4%	50.0%	(13.2)%

* Cash and cash equivalents include approximately $0.3 million and $0.6 million at December 31, 2007 and 2006, respectively, of cash included in the assets of discontinued operations.

Our dividend payout ratio for the year ended December 31, 2007 was approximately 52 percent compared to 55 percent and 128 percent for the years ended December 31, 2006 and 2005, respectively.

In 2008, we expect the total of our beginning cash balance, cash provided from operations and credit capacity under our available credit facilities to be sufficient to meet our normal operating commitments, to pay dividends and to fund a portion of our planned capital expenditures.

Our initial funding of the $940.0 million purchase price for the acquisition of the Aquila utility assets, and funding of additional related transaction costs is expected to be made through a borrowing on our $1.0 billion acquisition facility. Permanent financing to replace the funding from the acquisition facility and financing to provide for a portion of the costs of additional planned capital expenditures is expected to be provided through a combination of new equity, mandatory convertible securities, unsecured debt at the holding company level and internally-generated cash resources.

In 2007, we initiated a strategic assessment of several of our non-regulated power plants, including the possible sale of certain of those assets. A decision regarding any potential sale is expected to be made during the second quarter of 2008. Proceeds from any such sale would reduce our requirements for permanent financing related to the Aquila transaction and for financing of additional planned capital expenditures.

Cash Flow Activities

2007

In 2007, 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 decreased $7.6 million from the prior year amount, affected by a $26.1 million increase in income from continuing operations and the following:

A $12.0 million increase in cash flows from the change in current operating assets and liabilities. This is primarily driven by decreases in cash flow resulting from changes in net accounts receivable and accounts payable, which were more than offset by $26.6 million more in cash flows due to changes in materials, supplies and fuel during the year. Fluctuations in our materials, 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 $19.6 million decrease from the net change in derivative assets and liabilities primarily from derivatives associated with normal operations of our gas and oil marketing business and related commodity price fluctuations.

Higher depreciation, depletion and amortization expense of $5.6 million.

A decrease in cash flows resulting from the change in net regulatory assets and liabilities of $28.3 million primarily related to fuel cost adjustments for Cheyenne Light.

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We had cash outflows from investing activities of $260.3 million, including:

- Approximately $56.0 million for construction expenditures for the Valencia plant;
- Approximately $47.0 million for construction expenditures for Wygen II;
- Expenditures associated with oil and gas properties of approximately $72.9 million;
- Capitalized costs of approximately $19.1 million related to the Aquila acquisition;
- Approximately $13.6 million for construction expenditures for Wygen III; and
- Property, plant and equipment additions including ongoing maintenance capital in the normal course of business.

We had cash inflows from financing activities of $51.9 million primarily due to the following:

- Cash proceeds of $150.8 million from the issuance of common stock; and
- Cash proceeds of $110.0 million from the issuance of First Mortgage Bonds.

Partially offsetting the cash inflows from financing activities were the following:

- Net payment of $108.5 million on our credit facility;
- Payment of $50.3 million of cash dividends on common stock; and
- Payment of $47.9 million including the call of our outstanding debt with GE Capital of $23.5 million, as well as long-term debt maturities.

<u>2006</u>

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 $41.3 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:

- Construction expenditures of approximately $92.2 million for Wygen II;
- The acquisition of oil and gas assets in the Piceance Basin in Colorado for $75.4 million;
- 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 offsetting the cash outflows from investing activities was the following:

- $40.7 million of cash received from 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 the following:

- A $90.5 million increase in borrowings on our revolving bank facility.

Partially offsetting the cash inflows from financing activities were the following:

- The payment of $44.0 million of cash dividends on common stock;
- Net payment of $21.3 million related to the Black Hills Colorado project level debt refinancing; and
- Payment of long-term debt maturities.

Dividends

Dividends paid on our common stock totaled $1.37 per share in 2007. This reflects an increase in comparison to prior years dividend levels of $1.32 per share in 2006 and $1.28 per share in 2005. All dividends were paid out of operating cash flows. Our three-year annualized dividend growth rate was 3.4 percent. In November 2007 and February 2008, our Board of Directors declared quarterly dividends of $0.35 per share. If this dividend is maintained throughout 2008, it will be equivalent to $1.40 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

On February 22, 2007, we completed the issuance and sale of approximately 4.17 million shares of our common stock, par value $1.00 per share, at a sale price of $36.00 per share, in a private placement to institutional investors. Net proceeds of approximately $145.6 million were used for the repayment of debt.

Our principal sources of short-term liquidity are our revolving credit facility and cash provided by operations. Our liquidity position remained strong during 2007. As of December 31, 2007, we had approximately $81.0 million of cash unrestricted for operations. Approximately $2.9 million of the cash balance at December 31, 2007 was restricted by subsidiary debt agreements that limit our subsidiaries ability to dividend cash to the parent company.

Our $400 million revolving credit facility expires on May 4, 2010. 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 0.70 basis points over LIBOR (which equates to a 5.3 percent one-month borrowing rate as of December 31, 2007).

On March 13, 2007, we entered into a second amendment to our revolving credit facility. The second amendment (i) increased the limit for borrowings or other credit accommodations on the separate credit facility for our energy marketing subsidiary from $260 million to $300 million, (ii) increased the allowed total commitments under the revolving credit facility without requiring amendment of the facility from $500 million to $600 million, (iii) effective with the acquisition of certain electric and gas utility assets from Aquila, will increase the recourse leverage ratio limit from 0.65 to 1.00 to 0.70 to 1.00 for the first year after completion of the Aquila asset acquisition, reverting to 0.65 to 1.00 thereafter, and (iv) allowed for other modifications to enable us to complete the Aquila asset acquisition.

Our revolving credit facility can be used to fund our working capital needs and for general corporate purposes. At December 31, 2007, we had borrowings of $37.0 million and $49.1 million of letters of credit issued. Available capacity remaining on our revolving credit facility was approximately $313.9 million at December 31, 2007.

The 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, (or 0.70 to 1.00 for the first year after the Aquila acquisition); and

an interest expense coverage ratio of not less than 2.5 to 1.0.

If these covenants are violated, it would be considered an event of default entitling the lenders to terminate the remaining commitment and accelerate all principal and interest outstanding.

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, other debt obligations of $20 million or more. A default under the credit facility would permit the participating banks to restrict our 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 us from paying cash dividends unless no default, or no event of default, exists prior to, or would result after giving effect to such action.

Our consolidated net worth was $969.9 million at December 31, 2007, which was approximately $238.2 million in excess of the net worth we were required to maintain under the credit facility. Our long-term debt ratio at December 31, 2007 was 36.8 percent, our total debt leverage (long-term debt and short-term debt) was 43.4 percent, our recourse leverage ratio was approximately 44.5 percent and our interest expense coverage ratio for the twelve month period ended December 31, 2007 was 6.98 to 1.0.

In addition, Enserco, our energy marketing segment, has a $300 million uncommitted, discretionary line of credit to provide support for the purchase and sale of natural gas and crude oil. The line of credit is secured by all of Enserco s assets. This facility expires on May 9, 2008, prior to which we expect to renew the facility or enter into a replacement facility with similar acceptable terms. At December 31, 2007, there were outstanding letters of credit issued under the facility of $197.9 million, with no borrowing balances outstanding on the facility.

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During June 2007, we entered into a short-term, non-interest bearing, secured promissory note payable to Public Service Company of New Mexico in connection with the purchase of certain equipment and related assets for the Company s Valencia project in New Mexico. The Company recorded the promissory note payable at the stated amount of the debt of $30.0 million, less interest imputed at a rate of 6 percent totaling $0.9 million, for a net amount of $29.1 million. The secured promissory note was paid in full in December 2007.

On April 30, 2007, we called our outstanding debt with GE Capital in the amount of $23.5 million. The associated payment guarantees provided by us were also terminated.

On May 7, 2007, we entered into a senior unsecured $1.0 billion acquisition facility with ABN AMRO Bank N.V. as administrative agent and various other banks to provide for funding for our pending acquisition of Aquila s electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa. The acquisition facility is a committed facility to fund an acquisition term loan in a single draw in an amount of up to $1.0 billion. The commitment to fund the acquisition term loan terminates on August 5, 2008. Upon funding of the loan, the loan termination date is February 5, 2009.

The acquisition facility includes conditions precedent to funding which include consummation of the Aquila acquisition substantially in accordance with the existing asset purchase agreement. Borrowings under the term loan can be made under a base rate option, which is based on the then-current prime rate, or under a LIBOR option, which is based on the then-current LIBOR plus an applicable margin. The applicable margin for LIBOR borrowings is 55 basis points during the period from the initial funding under the term loan to six months thereafter, 67.5 basis points during the period from six months and one day after the initial funding to nine months thereafter, and 92.5 basis points during the period from nine months and one day after the initial funding until the loan maturity. The facility also includes certain customary affirmative and negative covenants which largely replicate the covenants under our existing revolving credit facility.

Our initial funding of the $940.0 million purchase price for the acquisition of the Aquila utility assets, and funding of additional related transaction costs is expected to be made through a borrowing on our $1.0 billion acquisition facility. Permanent financing to replace the funding from the acquisition facility and financing to provide for a portion of the costs of additional planned capital expenditures is expected to be provided through a combination of new equity, mandatory convertible securities, unsecured debt at the holding company level, and internally-generated cash resources.

In 2007, we initiated a strategic assessment of several of our non-regulated power plants, including the possible sale of certain of those assets. A decision regarding any potential sale is expected to be made during the second quarter of 2008. Proceeds from any such sale would reduce our requirements for permanent financing related to the Aquila transaction and for financing of additional planned capital expenditures.

Our Wygen I project debt of $128.3 million matures in June 2008. We intend to refinance this indebtedness with long-term financing prior to maturity.

On November 20, 2007, Cheyenne Light completed a $110.0 million First Mortgage Bond private placement offering. The bonds mature in 2037. The proceeds of the bond issuance were used to repay intercompany indebtedness incurred to finance a portion of the construction costs of our Wygen II power plant. The bonds have a 6.67 percent coupon with interest payable semi-annually. Prior to issuing the bonds, we entered into a treasury lock to hedge the interest rate on the bonds. The treasury lock cash settled on October 15, 2007, the pricing date of the bond offering, and resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds as additional interest expense.

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 can provide no assurance 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, 2007:

	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)]	$ 707,712	$ 143,183	$ 74,861	$ 251,483	$ 238,185
Unconditional purchase obligations [(d)]	212,587	40,028	54,384	28,108	90,067
Operating lease obligations [(e)]	16,895	2,597	4,215	1,748	8,335
Capital leases [(f)]	67	18	49		
Other long-term obligations [(g)]	29,910				29,910
Employee benefit plans[(h)]	17,462	1,627	3,987	3,190	8,658
Liability for unrecognized tax benefits in accordance with FIN 48	15,034		9,874	5,160	
Credit facilities	37,000	37,000			
Total contractual cash obligations	$ 1,036,667	$ 224,453	$ 147,370	$ 289,689	$ 375,155

(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: $43.3 million in 2008, $38.6 million in 2009, $36.4 million in 2010, $34.2 million in 2011 and $33.3 million in 2012. Variable rate interest using applicable rates is calculated as of December 31, 2007.

(c) We expect to refinance maturities on the Wygen I project debt of $128.3 million, which matures in June 2008, with a long-term financing prior to maturity.

(d) Unconditional purchase obligations include the capacity costs associated with our power purchase agreement with PacifiCorp and certain transmission, gas purchase and gas transportation and storage 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 2007 and price assumptions using existing prices at December 31, 2007. Our transmission obligations are based on filed tariffs as of December 31, 2007. 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 and Harbor power plants, a lease for compressor equipment and vehicle leases.

(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 2017.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2007, we had guarantees totaling $169.0 million in place. Of the $169.0 million, $141.0 million was related to guarantees associated with subsidiaries debt to third parties, which are recorded as liabilities on the Consolidated Balance Sheets, $24.0 million was related to performance obligations under subsidiary contracts and $4.0 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, 2007, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2007	Year Expiring
Guarantee obligations under the Wygen I Plant Lease	$ 111,018	2008
Guarantee obligations of Enserco under an agency agreement	7,000	2008
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
Guarantee for obligations and damages, if any, due under a power purchase agreement with Public Service Company of New Mexico related to the Valencia plant	12,000	2028
Indemnification for subsidiary reclamation/surety bonds	4,014	Ongoing
	$ 169,032	

Credit Ratings

As of February 2008, 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 our credit agreements, including the $1.0 billion acquisition facility, would be affected, increasing annual interest expense by approximately $2.1 million pre-tax based on December 31, 2007 balances.

Capital Requirements

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

	2007	2006	2005
	(in thousands)		
Acquisition costs:			
Payment for acquisition of net assets,			
net of cash acquired	$	$	$ 65,118
Property additions:			
Utilities			
Electric utility	35,743	24,992	18,162
Electric and gas utility[1]	69,220	107,348	30,536
Non-regulated energy			
Oil and gas	72,153	158,846[2]	71,799
Power generation	62,447[3]	8,557	6,095
Coal mining	4,991	5,807	6,517
Energy marketing	177	928	80
Corporate	22,316[4]	1,972	3,090
	267,047	308,450	136,279
Discontinued operations			7,459
	267,047	308,450	143,738
Common and preferred stock dividends	50,300	43,960	42,212
Maturities/redemptions of long-term debt	62,109	36,518	94,171
	$ 379,456	$ 388,928	$ 345,239

(1) Includes $50.4 million in 2007, $92.2 million in 2006 and $23.8 million in 2005 for Wygen II construction.
(2) Includes $75.4 million in 2006 for acquisitions in the Piceance Basin in Colorado.
(3) Includes $62.2 million for the Valencia construction.
(4) Includes $19.1 million for Aquila acquisition and development costs.

Our capital additions for 2007 were $267.0 million. The capital expenditures were primarily for the construction of the Wygen II power plant, the Valencia power plant, development drilling of oil and gas properties, capitalized costs associated with the Aquila acquisition and maintenance capital.

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.

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

	2008 (in thousands)	2009	2010
Utilities: [1]			
Electric utility [2][3]	$ 119,794	$ 120,500	$ 64,700
Electric and gas utility [4]	15,923	19,500	36,100
Non-regulated energy:			
Oil and gas	94,241	85,500	94,000
Power generation [5]	41,742	3,100	2,000
Coal mining	18,693	10,800	9,300
Energy marketing	135	800	800
Corporate	8,157	4,000	4,000
	$ 298,685	$ 244,200	$ 210,900

(1) Forecasted capital requirements are exclusive of the $940.0 million purchase price and related other costs for the pending acquisition of Aquila utility assets in 2008, and any maintenance capital subsequent to the acquisition.

(2) Electric utility capital requirements include approximately $56.9 million, $62.7 million and $9.7 million for the development of the Wygen III coal-fired plant in 2008, 2009 and 2010, respectively. Forecasted expenditures assume we will retain a 55 percent ownership interest in the plant.

(3) Electric utility capital requirements include approximately $17.2 million, $8.0 million and $20.0 million for Wygen III-related transmission projects in 2008, 2009 and 2010, respectively.

(4) Electric and gas utility capital requirements in 2010 include approximately $19.5 million for the purchase of an additional power plant.

(5) Includes $32.2 million for the Valencia power plant construction in 2008.

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 sectors expose us to a number of risks in the normal operation 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 and Crude Oil 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 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 derivative 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.

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, monitored and regularly reported to and reviewed by our Executive Risk Committee.

Daily risk management activities include reviewing positions in relation to established position limits, 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 and crude oil marketing and derivative commodity instruments at December 31, 2007 and 2006, 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 natural gas and crude oil marketing portfolio that has been recorded at fair value under a mark-to-market method of accounting during the year ended December 31, 2007 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2006	$	(1,454)[(a)]
Net cash settled during the year on positions that existed at December 31, 2006		10,376
Unrealized gain on new positions entered during the year and still existing at December 31, 2007		6,871
Realized loss on positions that existed at December 31, 2006 and were settled during the year		(8,923)
Unrealized loss on positions that existed at December 31, 2006 and still exist at December 31, 2007		(1,865)
Total fair value of energy marketing positions marked-to-market at December 31, 2007	$	5,005[(a)]

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

		December 31, 2007		December 31, 2006
Net derivative assets/(liabilities)	$	14,797	$	30,059
Fair value adjustment recorded in material, supplies and fuel		(9,792)		(31,513)
	$	5,005	$	(1,454)

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, 2007, we had a mark to fair value unrealized gain of $5.0 million for our natural gas and crude oil marketing activities. Of this amount, $5.6 million was current and $(0.6) million was non-current. The sources of fair value measurements were as follows (in thousands):

			Maturities			
Source of Fair Value		2008		2009 and Thereafter		Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$	(3,980)	$	(246)	$	(4,226)
Prices provided by other external sources		9,566		(335)		9,231
Modeled						
Total	$	5,586	$	(581)	$	5,005

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. 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, 2007 (in thousands)	December 31, 2006
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 5,005	$ (1,454)
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	24,952	24,574
Fair value of all forward positions (non-GAAP)	29,957	23,120
Liquidity reserve included in GAAP marked-to-market fair value	1,898	1,897
Fair value of all forward positions excluding Liquidity reserve (non-GAAP)	$ 31,855	$ 25,017

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 100 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 might 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 2008, 2009 and 2010 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	
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	11/07	03/08	5,000	$	7.86
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
San Juan El Paso	04/25/2007	Swap	04/09	06/09	2,500	$	7.21
San Juan El Paso	04/26/2007	Swap	04/09	06/09	2,500	$	7.15
San Juan El Paso	05/09/2007	Swap	04/09	06/09	5,000	$	7.24
CIG	05/09/2007	Swap	04/09	06/09	2,000	$	6.87
CIG	05/09/2007	Swap	01/09	03/09	2,000	$	8.37
San Juan El Paso	07/27/2007	Swap	07/09	09/09	5,000	$	7.63
CIG	09/07/2007	Swap	07/09	09/09	1,500	$	6.48
CIG	09/07/2007	Swap	04/08	12/08	1,500	$	5.91
AECO	09/07/2007	Swap	04/08	10/09	1,000	$	6.89
San Juan El Paso	10/29/2007	Swap	07/09	09/09	5,000	$	7.38
San Juan El Paso	10/29/2007	Swap	10/09	12/09	5,000	$	7.53
CIG	10/29/2007	Swap	10/09	12/09	1,500	$	7.07
NWR	11/16/2007	Swap	01/09	12/09	1,500	$	6.87
San Juan El Paso Basis	11/16/2007	Swap	04/08	12/08	-1,500	$	(0.93)
NWR Basis	11/16/2007	Swap	04/08	12/08	1,500	$	(1.64)
San Juan El Paso	12/13/2007	Swap	10/09	12/09	1,500	$	7.39
San Juan El Paso	12/13/2007	Swap	10/09	12/09	1,500	$	7.41
CIG	01/03/2008	Swap	01/10	03/10	2,000	$	7.49
NWR	01/03/2008	Swap	01/10	03/10	1,500	$	7.50
AECO	01/03/2008	Swap	11/09	03/10	1,000	$	8.07
San Juan El Paso	01/23/2008	Swap	01/10	03/10	5,000	$	7.50
AECO	01/23/2008	Swap	04/08	12/08	1,000	$	6.87

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)	Price
NYMEX	01/30/2007	Swap	Calendar 2008	5,000	$ 61.38
NYMEX	02/20/2007	Put	Calendar 2008	5,000	$ 60.00
NYMEX	03/07/2007	Swap	Calendar 2008	5,000	$ 67.34
NYMEX	03/23/2007	Swap	01/09 03/09	5,000	$ 67.60
NYMEX	03/26/2007	Put	Calendar 2008	5,000	$ 63.00
NYMEX	03/28/2007	Swap	01/09 03/09	5,000	$ 69.00
NYMEX	04/12/2007	Put	01/09 03/09	5,000	$ 65.00
NYMEX	04/26/2007	Swap	04/09 06/09	5,000	$ 70.25
NYMEX	05/10/2007	Swap	04/09 06/09	5,000	$ 69.10
NYMEX	05/29/2007	Put	04/09 06/09	5,000	$ 65.00
NYMEX	06/22/2007	Swap	07/09 09/09	5,000	$ 72.10
NYMEX	07/27/2007	Put	07/09 09/09	5,000	$ 65.00
NYMEX	09/12/2007	Swap	07/09 09/09	5,000	$ 71.20
NYMEX	09/12/2007	Put	01/09 03/09	5,000	$ 70.00
NYMEX	09/12/2007	Put	04/09 06/09	5,000	$ 70.00
NYMEX	10/29/2007	Put	10/09 12/09	5,000	$ 75.00
NYMEX	10/29/2007	Swap	10/09 12/09	5,000	$ 80.75
NYMEX	11/16/2007	Put	01/08 03/08	5,000	$ 75.00
NYMEX	11/16/2007	Put	04/08 06/08	5,000	$ 75.00
NYMEX	11/16/2007	Put	07/09 09/09	5,000	$ 75.00
NYMEX	11/16/2007	Put	10/09 12/09	5,000	$ 75.00
NYMEX	01/03/2008	Put	01/10 03/10	5,000	$ 80.00
NYMEX	01/03/2008	Swap	01/10 03/10	5,000	$ 88.70
NYMEX	01/23/2008	Swap	10/09 12/09	5,000	$ 83.10
NYMEX	01/23/2008	Swap	01/10 03/10	5,000	$ 82.90

The hedge agreements entered into by the Company had a fair value of approximately $(1.4) million as of December 31, 2007.

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 a gas-fired generation asset under a long-term contract that does 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 and purchased power resources 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, 2007, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 8.75 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, 2007 and 2006, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2007	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)
Interest rate swaps	$ 150,000	5.04%	8.75	$	$	$ 1,792	$ 4,274	$ (6,066)
December 31, 2006								
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102

Based on December 31, 2007 market interest rates and balances, a loss of approximately $1.8 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

In addition to the interest rate swaps above, during the third quarter of 2007, the Company entered into forward starting interest rate swaps with a total notional amount of $250.0 million and terms of 10 years or 20 years to hedge the risk of interest rate movement between the hedge dates and the expected pricing date for a portion of the Company s anticipated 2008 long-term debt financings. The swaps have a mandatory early termination date of June 30, 2008. As of December 31, 2007, the mark-to-market value was $(16.6) million. These swaps are designated as cash flow hedges and accordingly, any resulting gain or loss will be recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet and amortized into earnings as additional interest income or expense over the life of the related long-term financing.

On July 3, 2007, Cheyenne Light entered into a $110.0 million treasury lock to hedge a $110.0 million First Mortgage Bond offering which was completed in November 2007. The treasury lock cash settled on October 15, 2007, the pricing date of the offering, and resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds as additional interest expense.

At December 31, 2007, we had $222.0 million of outstanding, variable-rate, long-term debt of which $72.0 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 $0.7 million in 2008.

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

	2008	2009	2010	2011	2012	Thereafter	Total
Long-term debt							
Fixed rate [(a)]	$ 2,062	$ 2,078	$ 32,096	$ 2,116	$ 2,027	$ 445,285	$ 485,664
Average interest rate	9.59%	9.62%	8.16%	9.70%	9.52%	6.68%	6.98%
Variable rate [(b)]	$ 141,121	$ 12,857	$ 12,857	$ 12,857	$ 12,857	$ 29,499	$ 222,048
Average interest rate	5.79%	6.13%	6.13%	6.13%	6.13%	4.53%	6.06%
Total long-term debt	$ 143,183	$ 14,935	$ 44,953	$ 14,973	$ 14,884	$ 474,784	$ 707,712
Average interest rate	5.85%	6.61%	7.58%	6.63%	6.59%	6.55%	6.69%

(a) Excludes unamortized premium or discount.
(b) Approximately 68 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 provide assurance 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 77 percent of our credit exposure was with investment grade companies. The remaining credit exposure is with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments, or parental guarantees.

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, 2007 and 2006, we had outstanding forward exchange contracts to purchase approximately $28.0 million and $44.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.3) million at December 31, 2007 and 2006, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2007 were settled by February 25, 2008.

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 2007 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, who is also currently serving as interim Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2007, 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, 2007.

Deloitte & Touche, LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation s internal control over financial reporting as of December 31, 2007. Deloitte & Touche LLP s report on Black Hills Corporation s internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Black Hills Corporation

Rapid City, South Dakota

We have audited the internal control of Black Hills Corporation and subsidiaries (the Corporation) as of December 31, 2007, 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, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007, of the Corporation and our report dated February 27, 2008, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the

Corporation s adoption of new accounting standards.

DELOITTE & TOUCHE LLP

Minneapolis, MN

February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Black Hills Corporation

Rapid City, South Dakota

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the Corporation) as of December 31, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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 EITF Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining* Industry, on January 1, 2006, and SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement* Plans, on December 31, 2006. As discussed in Note 13 to the consolidated financial statements, the Corporation adopted FIN No. 48, *Accounting for Uncertainty in Income Taxes* on January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Corporation s internal control over financial reporting as of December 31, 2007, 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, 2008, which expressed an unqualified opinion on the Company s internal control over financial reporting.

DELOITTE & TOUCHE LLP

Minneapolis,MN

February 27, 2008

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BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2007 (in thousands)		2006		2005	
Revenues:						
Operating revenues	$	695,914	$	656,882	$	613,541
Operating expenses:						
Fuel and purchased power		175,919		203,473		189,752
Operations and maintenance		84,045		78,944		75,977
Administrative and general		115,568		91,883		91,246
Depreciation, depletion and amortization		99,700		94,083		88,116
Taxes, other than income taxes		37,816		35,827		34,424
Impairment of long-lived assets (Notes 1 and 11)		3,315				52,175
		516,363		504,210		531,690
Operating income		179,551		152,672		81,851
Other income (expense):						
Interest expense		(40,953)		(51,026)		(48,633)
Interest income		3,609		1,781		1,717
Allowance for funds used during construction - equity		4,803		2,647		
Other expense		(423)		(155)		(290)
Other income		786		786		1,143
		(32,178)		(45,967)		(46,063)
Income from continuing operations before minority interest and income taxes		147,373		106,705		35,788
Equity in earnings of unconsolidated subsidiaries		(1,231)		1,653		14,325
Minority interest		(377)		(510)		(277)
Income taxes		(45,641)		(33,802)		(17,044)
Income from continuing operations		100,124		74,046		32,792
(Loss) income from discontinued operations, net of income taxes		(1,352)		6,973		628
Net income		98,772		81,019		33,420
Preferred stock dividends						(159)
Net income available for common stock	$	98,772	$	81,019	$	33,261
Earnings per share of common stock:						
Basic-						
Continuing operations	$	2.70	$	2.23	$	1.00
Discontinued operations		(0.04)		0.21		0.02
Total	$	2.66	$	2.44	$	1.02
Diluted-						
Continuing operations	$	2.68	$	2.21	$	0.98
Discontinued operations		(0.04)		0.21		0.02
Total	$	2.64	$	2.42	$	1.00
Weighted average common shares outstanding:						
Basic		37,024		33,179		32,765
Diluted		37,414		33,549		33,288

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,	2007	2006
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 80,960	$ 36,939
Restricted cash	5,443	2,004
Accounts receivable (net of allowance for doubtful accounts of $4,588 and $4,202, respectively)	291,189	263,109
Materials, supplies and fuel	95,968	92,560
Derivative assets	37,208	69,244
Deferred income taxes	4,512	
Other current assets	14,569	9,221
Assets of discontinued operations	1,052	1,424
	530,901	474,501
Investments	19,216	23,808
Property, plant and equipment	2,490,565	2,242,396
Less accumulated depreciation and depletion	(667,031)	(596,029)
	1,823,534	1,646,367
Other assets:		
Goodwill	29,577	30,563
Intangible assets, net	21,026	24,429
Derivative assets	2,492	2,871
Other	46,120	42,137
	99,215	100,000
	$ 2,472,866	$ 2,244,676
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 242,813	$ 224,009
Accrued liabilities	116,197	95,020
Derivative liabilities	39,380	24,041
Accrued income taxes	833	19,561
Deferred income taxes		1,215
Notes payable	37,000	145,500
Current maturities of long-term debt	143,183	17,106
Liabilities of discontinued operations	1,551	2,526
	580,957	528,978
Long-term debt, net of current maturities	564,372	628,340
Deferred credits and other liabilities:		
Deferred income taxes	207,735	174,332
Derivative liabilities	9,375	1,530
Other	135,405	116,297
	352,515	292,159
Minority interest	5,167	5,158
Commitments and contingencies (Notes 6, 7, 8, 12, 17, 18 and 19)		
Stockholders equity:		
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 37,842,221 shares in 2007 and 33,404,902 shares in 2006	37,842	33,405
Additional paid-in capital	560,475	409,826
Retained earnings	397,393	348,245

Treasury stock at cost 45,916 shares in 2007 and 35,700 shares in 2006	(1,347)	(920)
Accumulated other comprehensive loss	(24,508)	(515)
	969,855	790,041
	$ 2,472,866	$ 2,244,676

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,	2007	2006	2005
	(in thousands)		
Operating activities:			
Net income	$ 98,772	$ 81,019	$ 33,420
Loss (income) from discontinued operations, net of tax	1,352	(6,973)	(628)
Income from continuing operations	100,124	74,046	32,792
Adjustments to reconcile income from continuing operations to net cash provided by operating activities-			
Depreciation, depletion and amortization	99,700	94,083	88,116
Impairment of long-lived assets	3,315		52,175
Issuance of common stock and treasury stock for operating expense	4,585	2,760	1,917
Net change in derivative assets and liabilities	(10,763)	8,864	(6,536)
Deferred income taxes	31,409	33,233	(8,783)
Change in operating assets and liabilities-			
Materials, supplies and fuel	18,331	(8,300)	(16,787)
Accounts receivable and other current assets	(32,808)	2,208	(46,333)
Accounts payable and other current liabilities	49,258	28,853	52,515
Regulatory assets and liabilities	(9,434)	18,879	17,254
Other operating activities	2,867	7,631	7,278
Net cash provided by operating activities of continuing operations	256,584	262,257	173,608
Net cash (used in) provided by operating activities of discontinued operations	(4,505)	(2,562)	1,241
Net cash provided by operating activities	252,079	259,695	174,849
Investing activities:			
Property, plant and equipment additions	(261,371)	(308,450)	(136,279)
Payment for acquisition of net assets, net of cash acquired			(65,118)
Other investing activities	(3,110)	(1,154)	(3,861)
Net cash used in investing activities of continuing operations	(264,481)	(309,604)	(205,258)
Net cash provided by investing activities of discontinued operations	4,209	41,507	95,551
Net cash used in investing activities	(260,272)	(268,097)	(109,707)
Financing activities:			
Dividends paid on common and preferred stock	(50,300)	(43,960)	(42,212)
Common stock issued	150,787	4,059	12,212
(Decrease) increase in short-term borrowings, net	(108,500)	90,500	31,000
Long-term debt issuance	110,000	90,000	
Long-term debt repayments	(47,891)	(126,518)	(94,171)
Other financing activities	(2,178)	(2,347)	(2,279)
Net cash provided by (used in) financing activities of continuing operations	51,918	11,734	(95,450)
Net cash provided by financing activities of discontinued operations			
Net cash provided by (used in) financing activities	51,918	11,734	(95,450)
Increase (decrease) in cash and cash equivalents	43,725	3,332	(30,308)
Cash and cash equivalents:			
Beginning of year	37,530[b]	34,198[c]	64,506[d]
End of year	$ 81,255[a]	$ 37,530[b]	$ 34,198[c]
Supplemental disclosure of cash flow information:			
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$ 25,901	$ 25,029	$ 13,270
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 44,700	$ 48,905	$ 47,987
Income taxes paid (refunded)	$ 14,204	$ (2,685)	$ 12,743

(a) Includes approximately $0.3 million of cash included in the assets of discontinued operations.
(b) Includes approximately $0.6 million of cash included in the assets of discontinued operations.
(c) Includes approximately $2.4 million of cash included in the assets of discontinued operations.
(d) Includes approximately $8.6 million of cash included in the assets of discontinued operations.

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

BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

	Year Ended December 31, 2007	2006	2005
	(in thousands, except share amounts)		
Common stock:			
Balance beginning of year	$ 33,405	$ 33,223	$ 32,595
Issuance of common stock	4,437	182	628
Balance end of year (37,842,221 shares, 33,404,902, shares and 33,222,522 shares issued in 2007, 2006 and 2005, respectively)	37,842	33,405	33,223
Additional paid-in capital:			
Balance beginning of year	409,826	404,035	384,439
Issuance of common stock	150,630	5,791	18,751
Issuance of treasury stock, net	19		845
Balance end of year	560,475	409,826	404,035
Retained earnings:			
Balance beginning of year	348,245	313,217	322,009
Net income	98,772	81,019	33,420
Dividends on common stock	(50,300)	(43,960)	(42,053)
Dividends on preferred stock			(159)
Cumulative effect of change in accounting principle (see Notes 1 and 13)	676	(2,031)	
Balance end of year	397,393	348,245	313,217
Treasury stock:			
Balance beginning of year	(920)	(1,766)	(2,838)
(Purchase) issuance of treasury stock, net	(427)	846	1,072
Balance end of year (45,916 shares, 35,700 shares and 66,938 shares issued in 2007, 2006 and 2005, respectively)	(1,347)	(920)	(1,766)
Accumulated other comprehensive (loss) income:			
Balance beginning of year	(515)	(9,830)	(7,607)
Other comprehensive (loss) income, net of tax (see Note 14)	(23,993)	15,429	(2,223)
Adoption of accounting pronouncement (see Note 17)		(6,114)	
Balance end of year	(24,508)	(515)	(9,830)
Total stockholder s equity	$ 969,855	$ 790,041	$ 738,879

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Comprehensive income:			
Net income available for common stock	$ 98,772	$ 81,019	$ 33,261
Other comprehensive (loss) income, net of tax (see Note 14)	(23,993)	15,429	(2,223)
	$ 74,779	$ 96,448	$ 31,038

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, 2007, 2006 and 2005

(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: Utilities and Non-regulated energy (previously Retail services and Wholesale energy, respectively). The Utilities group includes 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. The Company operates its Non-regulated 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. Amounts related to Black Hills Energy Resources, Black Hills FiberSystems and Pepperell 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 $13.2 million, $10.8 million and $10.1 million in 2007, 2006 and 2005, 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:

Major Classification	2007 (in thousands)	2006
Materials and supplies	$ 35,037	$ 31,946
Fuel	5,025	9,663
Gas and oil held by energy marketing	55,906	50,951
Total materials, supplies and fuel*	$ 95,968	$ 92,560

* As of December 31, 2007 and 2006, market adjustments related to gas and oil held by energy marketing and recorded in inventory, were $(9.8) million and $(31.5) 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 equity 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 $14.8 million, $7.2 million and $0.7 million in 2007, 2006 and 2005, 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 estimated future expenditures to be incurred in developing proved reserves as well as estimated dismantlement and abandonment costs, net of estimated salvage values 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.

Those costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized.

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 commodity 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 changes in facts, such as market price increases, 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 2007, 2006 or 2005.

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 for impairment. The Company performs this annual review during the fourth quarter of each year (or more frequently if impairment indicators arise). Intangible assets with a finite 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, 2007 and 2006 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
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

Tax adjustment on acquisition earn-out (see Note 18)		(392)		
Impairment losses		(594)		(314)
Amortization expense				(3,089)
Balance at December 31, 2007, net of accumulated amortization	$	29,577	$	21,026

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 $49.1 million, with accumulated amortization of $28.1 million at December 31, 2007 and $50.3 million, with accumulated amortization of $25.9 million at December 31, 2006. Amortization expense for intangible assets was $3.1 million, $3.1 million and $3.3 million in 2007, 2006 and 2005, respectively. Amortization expense for existing intangible assets is expected to be approximately $3.0 million a year through 2009, $2.2 million in 2010 and $0.4 million in 2011 through 2012.

During the third quarter of 2007, the Company wrote off intangible assets of $0.3 million, net of accumulated amortization of $0.8 million, related to the impairment of the Ontario plant. The impairment charge is a result of a thermal host contract expiration without a long-term extension (see Note 11).

During the second quarter of 2007, the Company wrote off goodwill of approximately $0.4 million for tax adjustments related to the acquisition earn-out (see Note 18). During the fourth quarter of 2007, the Company wrote off goodwill of approximately $0.6 million, net of accumulated amortization of $0.1 million, related to the write-down of the Company s investments in the Rupert and Glenns Ferry partnerships. The write-downs were the result of impairment charges by the partnerships primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of the partnerships power supply agreements (see Note 11).

Additions to goodwill in 2006 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.

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.

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 or depleted 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 and depleted pursuant to our full cost method.

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 2007, the Company recorded a $2.7 million pre-tax impairment charge to reduce the carrying value of the Ontario power plant and related intangibles and a $0.6 million pre-tax impairment charge of goodwill related to lower partnership earnings as a result of a partnership impairment charge for the Glenns Ferry and Rupert power plants, in which we hold a 50 percent interest and account for under the equity method. 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.

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, typically only after the execution of definitive agreements, 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 VIE as defined by FIN 46.

Earnings attributable to minority ownership are shown on the accompanying Consolidated Statements 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 utility 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 the Utilities 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.

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

	2007 (in thousands)		2006	
Regulatory assets				
Deferred energy and fuel costs	$	939	$	1,002
Deferred electric and gas cost adjustments		1,368		
Unamortized loss on reacquired debt		2,809		3,060
Allowance for funds used during construction		7,880		3,991
Employee benefit plans		2,998		10,817
Derivative		4,276		
Other		729		529
	$	20,999	$	19,399
Regulatory liabilities				
Deferred energy costs	$	4,779	$	9,916
Cost of removal		22,431		18,389
Employee benefit plans		1,738		598
Unamortized gain on reacquired debt		1,260		
Other		2,874		3,287
	$	33,082	$	32,190

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 reacquired debt, 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.

Cheyenne Light periodically files with the WPSC an ECA and a GCA to be included in tariff rates for the following periods. The ECA and GCA are based on forecasts of the upcoming energy costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that energy costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. 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.

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AFUDC represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. AFUDC for the years ended December 31, 2007, 2006 and 2005 was $11.2 million, $5.6 million, and $0.7 million, respectively. The equity component of AFUDC for 2007, 2006 and 2005 was $4.8 million, $2.6 million and $0.4 million, respectively. The borrowed funds component of AFUDC for 2007, 2006 and 2005 was $6.4 million, $3.0 million and $0.3 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.

The Company accounts for uncertainty in income taxes recognized in the financial statements in accordance with FIN 48. The unrecognized tax benefit is classified in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheet (see Note 13).

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, in accordance with SFAS 133 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 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):

	2007		2006		2005	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$ 100,124		$ 74,046		$ 32,792	
Less: preferred stock dividends					(159)	
Basic Income from continuing operations	100,124	37,024	74,046	33,179	32,633	32,765
Dilutive effect of:						
Stock options		111		87		160
Convertible preferred stock					159	97
Contingent shares issuable for prior acquisition		159		159		159
Others		120		124		107
Diluted Income from continuing operations	$ 100,124	37,414	$ 74,046	33,549	$ 32,792	33,288

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):

	2007	2006	2005
Options to purchase common stock	34	153	123

Recently Adopted Accounting Pronouncements

FIN 48

During June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The Company adopted FIN 48 on January 1, 2007. See Note 13, Income Taxes for further discussion.

EITF 04-6

The Company adopted EITF 04-6 on January 1, 2006. EITF 04-6 provides that stripping costs incurred should be included in the costs of inventory produced during the period the 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.

SAB No. 108

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.

Recently Issued Accounting Pronouncements

SFAS 157

During September 2006, the FASB issued SFAS 157, which applies under other accounting pronouncements that require or permit fair value measurements. This Statement defines fair value, establishes a framework for measuring fair value in accordance with GAAP and expands disclosures about fair value measurements. The Company is subject to the provisions of SFAS 157 beginning January 1, 2008. Management is currently evaluating the impact SFAS 157 will have on the Company s consolidated financial statements; however, management believes it will likely be required to provide additional disclosures as part of future financial statements, beginning with first quarter of 2008.

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 position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. The Company applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 will require the measurement of the funded status of the plan to coincide with the date of the year end statement of financial position. The funded status of the Company s pension and other postretirement benefit plans are currently measured as of September 30, 2007. See Note 17, Employee Benefit Plans for further discussion of Defined Benefit Pension and Other Postretirement Plans.

SFAS 159

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

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. Management is currently evaluating the impact SFAS 141(R) will have on the Company s consolidated financial statements.

SFAS 160

In December 2007, the FASB issued SFAS 160. SFAS 160 amends ARB 51 and requires:

ownership interests in subsidiaries held by other parties other than the parent be clearly identified on the consolidated statement of financial position within equity, but separate from the parent s equity;

consolidated net income attributable to the parent and to the non-controlling interest be clearly identified on the face of the consolidated statement of income;

changes in a parent s ownership interest while the parent retains controlling financial interest be accounted for consistently as equity transactions;

when a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value; and

sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners.

SFAS 160 is effective for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Management does not expect the adoption of SFAS 160 to have a significant effect on the Company s consolidated financial statements.

(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, storage agreements and forward foreign exchange contracts. Energy marketing business activities are conducted within the parameters as defined and allowed by the BHCRPP and the CRPP.

For the years ended December 31, 2007, 2006 and 2005, 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:

	2007		2006	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu)				
Natural gas basis swaps purchased	125,577	36	138,111	22
Natural gas basis swaps sold	128,892	36	148,720	22
Natural gas fixed-for-float swaps purchased	42,326	24	38,239	16
Natural gas fixed-for-float swaps sold	59,253	24	59,061	15
Natural gas physical purchases	90,583	15	87,782	22
Natural gas physical sales	98,888	27	106,500	34
Natural gas options purchased	3,472	10	22,373	15
Natural gas options sold	3,472	10	22,373	15
(thousands of Bbls of oil)				
Crude oil physical purchases	4,991	12	1,600	4
Crude oil physical sales	3,800	12	1,367	7
Crude oil swaps purchased	495	12	240	12
Crude oil swaps sold	495	12	240	12
(Dollars, in thousands)				
Canadian dollars purchased	$28,000	2	$44,000	1

Derivatives and certain natural gas and oil marketing activities were marked to fair value on December 31, 2007 and 2006, 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, 2007 and 2006 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (Loss)
December 31, 2007	$ 32,286	$ 1,901	$ 16,908	$ 2,482	$ 14,797
December 31, 2006	$ 53,728	$ 4	$ 23,296	$ 377	$ 30,059

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, 2007 and 2006, the market adjustments recorded in inventory were $(9.8) million and $(31.5) 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, 2007 and 2006, the Company had a portfolio of swaps and options 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, 2007 and 2006, 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, 2007 and 2006 the Company had the following swaps, options and related balances (in thousands):

December 31, 2007	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	495,000	1.00	$ 352	$	$ 3,506	$ 1,794	$ (5,300)	$ 352
Natural gas swaps	11,406,000	1.59	4,332	591	507	825	3,587	4
			$ 4,684	$ 591	$ 4,013	$ 2,619	$ (1,713)	$ 356
December 31, 2006								
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)

*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 2008. Based on December 31, 2007 market prices, a minimal gain will be realized and reported in earnings during 2008. These estimated realized gains for 2008 were calculated using December 31, 2007 market prices. Estimated and actual realized gains will likely change during 2008 as market prices change.

Fuel in Storage

On December 31, 2007 and 2006, 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, 2007								
Natural gas swaps	610,000	0.33	$ 238	$	$ 68	$	$ 170	$
December 31, 2006								
Natural gas swaps	380,000	0.25	$ 1,220	$	$	$	$ 878	$ 342

*gas in MMBtu

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

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, the market adjustments recorded in inventory were $(0.3) million.

Power Generation

The Company has a portfolio of natural gas fueled generation assets located throughout several western states. Most of these generation assets are locked into long-term tolling contracts with third parties whereby any commodity price risk is assumed by the third party. However, the Company does possess market risk for fuel purchases under the current long-term contract at its Las Vegas I plant.

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 considers 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 and purchase power resources exceed its anticipated load requirements plus a required reserve margin.

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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, 2007, the Company had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 8.75 years and a fair value of $(6.1) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2007 and 2006 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)
December 31, 2007								
Interest rate swaps	$ 150,000	5.04%	8.75	$	$	$ 1,792	$ 4,274	$ (6,066)
December 31, 2006								
Interest rate swaps	$ 150,000	5.04%	9.75	$ 287	$ 867	$ 74	$ 978	$ 102

Based on December 31, 2007 market interest rates and balances, a loss of approximately $1.8 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

In addition to the interest rate swaps above, during the third quarter of 2007, the Company entered into forward starting interest rate swaps with a total notional amount of $250.0 million and terms of 10 years or 20 years to hedge the risk of interest rate movement between the hedge dates and the expected pricing date for a portion of the Company s anticipated 2008 long-term debt financings. The swaps have a mandatory early termination date of June 30, 2008. As of December 31, 2007, the mark-to-market value was $(16.6) million. These swaps are designated as cash flow hedges and accordingly, any resulting gain or loss will be recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet and amortized into earnings as additional interest income or expense over the life of the related long-term financing.

On July 3, 2007, Cheyenne Light entered into a $110.0 million treasury lock to hedge a $110.0 million First Mortgage Bond offering which was completed in November 2007. The treasury lock cash settled on October 15, 2007, the pricing date of the offering, and resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds 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, 2007 and 2006, the Company had outstanding forward exchange contracts to purchase approximately $28.0 million and $44.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.3) million at December 31, 2007 and 2006, 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, 2007 were settled by February 25, 2008.

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 mitigating 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 December 31, 2007, the Company s credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Approximately 77 percent of the credit exposure was with investment grade companies. The remaining credit exposure was with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments or parental guarantees.

(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 5.7 percent 4.4 percent and 5.1 percent interest in 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 $3.0 million and $5.5 million, as of December 31, 2007 and 2006, respectively. As of, and for the year ended December 31, 2007, the funds had assets of $43.1 million, liabilities of $0.3 million and net income of $8.0 million. 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. The Energy Investors Fund, L.P. was fully liquidated as of December 31, 2007. 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 was $0 as of December 31, 2007, and $4.4 million as of December 31, 2006. In December 2007, the Rupert and Glenns Ferry partnerships wrote down the carrying amounts of their property, plant and equipment to reflect the partnerships assessment of the recoverability of their respective carrying amounts primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of power supply agreements. As a result, the Company s carrying amount of the two partnership investments were reduced by a total of $3.9 million to reflect equity losses from the partnerships asset impairment adjustments. In addition, the Company wrote off a total of $0.6 million of net goodwill for the two partnerships directly related to the Company s 50 percent investments in the partnerships. As of, and for the year ended December 31, 2007, these projects had assets of $4.5 million, liabilities of $7.8 million and net loss of $(11.6) million. 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.

(4) PROPERTY, PLANT AND EQUIPMENT

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

Utilities Group

Electric Utility	2007	2007 Weighted Average Useful Life	2006	2006 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 322,572	47	$ 325,616	47	30-62
Transmission	70,897	45	70,731	45	35-55
Distribution	238,799	37	232,299	37	25-40
Plant acquisition adjustment	4,870	32	4,870	32	32
General	38,944	22	34,533	22	10-50
Total electric plant	676,082		668,049		
Less accumulated depreciation and amortization	266,583		265,247		
Electric plant net of accumulated depreciation and amortization	409,499		402,802		
Construction work in progress	19,018		7,586		
Net electric plant	$ 428,517		$ 410,388		

Electric and Gas Utility	2007	2007 Weighted Average Useful Life	2006	2006 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 4,307	45	$		45
Transmission	2,486	44	2,489	44	40-45
Electric distribution	77,633	44	68,779	44	15-45
General	317	25	227	27	10-25
Gas plant:					
Distribution	40,817	55	37,955	56	15-65
General	249	25	135	27	10-25
General	8,230	25	7,360	27	3-25
Total	134,039		116,945		
Less accumulated depreciation and amortization	10,063		6,861		
Total net of accumulated depreciation and amortization	123,976		110,084		
Construction work in progress	181,786		130,310		
Net electric and gas	$ 305,762		$ 240,394		

2007

Non-regulated 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	Weighted Average Useful Life	Lives (in years)
Coal mining	$ 81,046	$ 45,587	$ 35,459	$ 5,675	$ 41,134	15	3-25
Oil and gas	559,394	153,050	406,344		406,344	24	3-25
Energy marketing	2,389	1,603	786		786	4	3-7
Power generation	736,723	182,138	554,585	61,635	616,220	29	3-40
	$ 1,379,552	$ 382,378	$ 997,174	$ 67,310	$ 1,064,484		

2006

Non-regulated 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	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		

2007

	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	Weighted Average Useful Life	Lives (in years)
Corporate	$ 19,474	$ 8,007	$ 11,467	$ 13,304	$ 24,771	4	3-10

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	Weighted Average Useful Life	Lives (in years)

Corporate	$	10,716	$	5,826	$	4,890	$	10	$	4,900	4	3-10

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(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, 2007, Black Hills Power s investment in the Plant included $80.4 million in electric plant and $43.5 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 $7.3 million, $7.9 million and $6.1 million for the years ended December 31, 2007, 2006 and 2005, 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 $21.5 million, $16.8 million and $18.1 million for the years ended December 31, 2007, 2006 and 2005, 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, 2007, 2006 and 2005, Black Hills Power s share of direct expenses was $0.1 million, $0.1 million and $0.2 million, respectively. As of December 31, 2007, Black Hills Power s investment in the transmission tie was $19.8 million, with $2.0 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, 2007, the Company s investment in the Gas Plant included $4.1 million in plant and equipment and $3.6 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company s share of revenues of the Gas Plant was $2.8 million, $3.1 million and $3.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. The Company s share of direct expenses for the Gas Plant was $0.3 million for each of the years ended December 31, 2007, 2006 and 2005. 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):

	2007	2006
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes	(157)	(186)
	224,843	224,814
First mortgage bonds:		
Electric utility		
8.06% due 2010	30,000	30,000
9.49% due 2018	3,100	3,390
9.35% due 2021	23,310	24,975
7.23% due 2032	75,000	75,000
Electric and gas utility		
7.50% due 2024		7,200
6.67% due 2037[a]	110,000	
Industrial development revenue bonds, variable rate, at 3.59% due 2021[d]	7,000	7,000
Industrial development revenue bonds, variable rate, at 3.59% due 2027[d]	10,000	10,000
Unamortized debt premium on 7.5% first mortgage bonds due 2024		1,600
	258,410	159,165
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 due 2010[b]		24,214
Other	3,459	3,553
	22,109	46,417
Project financing floating rate debt:		
Valmont and Arapahoe at 6.13% due 2013 [d]	73,929	86,786
Wygen I project at 5.76% due 2008[c][d]	128,264	128,264
	202,193	215,050
Total long-term debt	707,555	645,446
Less current maturities	(143,183)	(17,106)
Net long-term debt	$ 564,372	$ 628,340

(a) In November 2007, the Company issued $110 million in First Mortgage bonds. Proceeds were used to finance a portion of the construction costs of the Wygen II power plant.

(b) Floating rate debt, 86 percent secured by Gillette combustion turbine and 14 percent secured by a spare LM6000 turbine. Balance paid in full in April 2007.

(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, 2007.

At December 31, 2007, approximately 68 percent, or $150.0 million, of the Company s $222.0 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, 2007. Also, certain of the subsidiaries debt agreements provide that approximately $2.9 million of the subsidiaries cash balance at December 31, 2007 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: $143.2 million in 2008, $14.9 million in 2009, $45.0 million in 2010, $15.0 million in 2011, $14.9 million in 2012 and $474.7 million thereafter.

(7) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $400.0 million at December 31, 2007 and 2006. The $400.0 million line of credit outstanding at December 31, 2007 is a revolving credit facility, which expires May 4, 2010. The Company had $37.0 million of borrowings and $49.1 million of letters of credit and $145.5 million of borrowings and $49.4 million of letters of credit issued on the lines at December 31, 2007 and 2006, respectively. The Company has no compensating balance requirements associated with these lines of credit.

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 0.70 basis points over LIBOR (which equates to a 5.3 percent one-month borrowing rate as of December 31, 2007).

On March 13, 2007, we entered into a second amendment to our revolving credit facility. The second amendment (i) increased the limit for borrowings or other credit accommodations on the separate credit facility for our energy marketing subsidiary from $260 million to $300 million, (ii) increased the allowed total commitments under the revolving credit facility without requiring amendment of the facility from $500 million to $600 million, (iii) effective with the acquisition of certain electric and gas utility assets from Aquila, will increase the recourse leverage ratio limit from 0.65 to 1.00 to 0.70 to 1.00 for the first year after completion of the Aquila asset acquisition, reverting to 0.65 to 1.00 thereafter, and (iv) allowed for other modifications to enable us to complete the Aquila asset acquisition.

In addition to the above lines of credit, at December 31, 2007, Enserco has a $300.0 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 9, 2008. At December 31, 2007 and 2006, there were outstanding letters of credit issued under the facility of $197.9 million and $158.7 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, 2007, 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 associated ARO accretion expense is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. 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 12/31/06	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/07
Oil and gas	$ 13,240	$ 1,934	$ (860)	$ 638	$ 14,952
Mining	16,005	233	(1,748)	288	14,778
Electric and gas utility	171			9	180
Total	$ 29,416	$ 2,167	$ (2,608)	$ 935	$ 29,910

	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

(9) COMMON AND PREFERRED STOCK

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 offering. The Company used the approximate $145.6 million of net proceeds from this offering for debt reduction.

These shares were not initially registered under the Securities Act of 1933, therefore restricting the purchasers ability to offer or sell the shares. The Company s resale shelf registration statement was declared effective by the SEC on

March 31, 2007. In addition, the Company must maintain the shelf registration statement with the SEC, allowing resale of the restricted shares, until all related shares have been resold or cease to be restricted. At December 31, 2007, 279,050 shares have not been resold under the registration statement. If the Company fails to maintain an effective shelf registration statement in accordance with the terms of the offering agreements, it may be required to pay damages to the purchasers at a per thirty-day rate of 1.0 percent of the related share purchase price until the default is cured. The total damage payments under the agreements are limited to 10.0 percent of the related share purchase price. The

Company believes the likelihood of making any payments under the damage provisions is remote and accordingly has not recognized any liability within its consolidated financial statements.

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 982,029 shares available to grant at December 31, 2007.

At December 31, 2007, 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	
Net income available for common stock, as reported	$	33,261
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(689)
Pro forma net income	$	32,572
Earnings per share:		
As reported		
Basic		
Continuing operations	$	1.00
Discontinued operations		0.02
Total	$	1.02
Diluted		
Continuing operations	$	0.98
Discontinued operations		0.02
Total	$	1.00
Pro forma		
Basic		
Continuing operations	$	0.97
Discontinued operations		0.02
Total	$	0.99
Diluted		
Continuing operations	$	0.96
Discontinued operations		0.02
Total	$	0.98

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, 2007, 2006 and 2005 was $5.8 million ($3.8 million, after-tax), $2.6 million ($1.7 million, after-tax) and $3.2 million ($2.1 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, 2007, total unrecognized compensation expense related to stock options and other non-vested stock awards is $3.2 million and is expected to be recognized over a weighted-average period of 1.9 years.

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, 2007 is as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at January 1, 2007	725	$ 29.61		
Granted				
Forfeited/cancelled	(4)	36.01		
Expired				
Exercised	(182)	29.82		
Balance at December 31, 2007	539	$ 29.49	4.0	$ 7,878
Exercisable at December 31, 2007	528	$ 29.42	3.9	$ 7,749

The weighted-average grant-date fair value of options granted during the years ended December 31, 2006 and 2005 was $3.79 and $6.93, respectively. No options were granted in 2007. 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, 2007, 2006 and 2005 was $1.9 million, $0.8 million and $5.2 million, respectively. The total fair value of shares vested during the years ended December 31, 2007, 2006 and 2005 was $0.4 million, $0.6 million and $1.0 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
Weighted average risk-free interest rate[2]	4.94%	3.90%
Weighted average expected price volatility[3]	21.54%	42.27%
Weighted average expected dividend yield[4]	3.98%	4.17%
Expected life in years[5]	7	7

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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.

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, 2007, 2006 and 2005 was $4.7 million, $3.7 million and $10.2 million, respectively. The tax benefit realized from the exercise of shares granted for the years ended December 31, 2007, 2006 and 2005 was $0.7 million, $0.3 million and $1.8 million, respectively, and was recorded as an increase to equity.

As of December 31, 2007, there was less than $0.1 million of unrecognized compensation expense related to stock options that is expected to be recognized over a weighted-average period of 1.2 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, 2007 is as follows:

	Stock And Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Balance at January 1, 2007	105	$ 33.76
Granted	58	38.67
Vested	(47)	32.91
Forfeited	(1)	36.66
Balance at December 31, 2007	115	$ 36.58

The weighted-average grant-date fair value of restricted stock and restricted stock units granted and the total fair value of shares vested during the years ended December 31, 2007, 2006 and 2005 was as follows:

	Weighted Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2007	$ 38.67	$ 1,975
2006	$ 35.57	$ 1,332
2005	$ 31.64	$ 1,161

As of December 31, 2007, there was $2.5 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, 2007 are as follows:

Grant Date	Performance Period		Target Grant of Shares (in thousands)
January 1, 2005	January 1, 2005	December 31, 2007	37
January 1, 2006	January 1, 2006	December 31, 2008	32
January 1, 2007	January 1, 2007	December 31, 2009	35

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 $1.6 million at December 31, 2007 will be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31, 2007 and changes during the twelve-month period ended December 31, 2007, is as follows:

	Equity Portion		Liability Portion	
	Shares (in thousands)	Weighted-Average Grant Date Fair Value	Shares (in thousands)	Weighted-Average December 31, 2007 Fair Value
Balance at January 1, 2007	45	$ 32.60	45	
Granted	18	34.17	18	
Forfeited				
Vested	(11)	33.45	(11)	
Balance at December 31, 2007	52	$ 33.43	52	$ 53.20

The grant date fair value for the performance shares granted in 2007 and 2006 were determined by Monte Carlo simulation using a blended volatility of 20 percent and 21 percent, respectively, 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 was equal to the market value of the common stock on the grant date. The weighted-average grant-date fair value of performance share awards granted in the years ended December 31, 2007, 2006 and 2005 was as follows:

	Weighted Average Grant Date Fair Value
2007	$ 34.17
2006	$ 32.06
2005	$ 29.97

Performance plan payouts have been as follows:

Performance Period	Year of Payment	Stock Issued	Cash Paid (in thousands)	Total Intrinsic Value
March 1, 2004 to December 31, 2006	2007	4	$ 160	$ 320
March 1, 2004 to December 31, 2005	2006	12	$ 419	$ 837

On January 31, 2008, the Compensation Committee of the Board of Directors determined that the Company s total shareholder return for the January 1, 2005 to December 31, 2007 performance period was at the 87th percentile of its peer group and approved a payout equal to 175 percent of target shares. This payout was fully accrued at December 31, 2007.

As of December 31, 2007, there was $0.7 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.4 years.

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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. At December 31, 2007, 28,210 shares of unissued common stock were available for future offering under the Plan.

The Company issued 33,143 shares of common stock with an intrinsic value of $1.2 million in the twelve months ended December 31, 2007 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2006. The Company issued 25,685 and 3,266 shares of common stock in 2006 and 2005, 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 2008 for the 2007 Short-term Annual Incentive Plan. The payout was fully accrued at December 31, 2007.

Dividend Restrictions

The Company s credit facility contains restrictions on the payment of cash dividends under a circumstance of default or event of 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 (or 0.70 to 1.00 for the first year after the Aquila acquisition); 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, 2007, the Company was in compliance with the above covenants.

Treasury Shares

The Company acquired 767, 6,224 and 2,771 shares of treasury stock related to forfeitures of unvested restricted stock in 2007, 2006 and 2005, respectively, and 16,418, 8,095 and 16,872 shares related to the share withholding for the payment of taxes associated with the vesting of restricted shares and stock option exercise stock swaps in 2007, 2006 and 2005, respectively.

The Company utilized 8,030, 46,785 and 71,284 shares of treasury stock in 2007, 2006 and 2005, respectively, related to grants from the different equity plans.

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. There are no longer any outstanding shares of preferred stock after this conversion.

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(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2007 Carrying Amount	Fair Value	2006 Carrying Amount	Fair Value
Cash and cash equivalents	$ 80,960	$ 80,960	$ 36,939	$ 36,939
Restricted cash	$ 5,443	$ 5,443	$ 2,004	$ 2,004
Derivative financial instruments assets	$ 39,700	$ 39,700	$ 72,115	$ 72,115
Derivative financial instruments liabilities	$ 48,755	$ 48,755	$ 25,571	$ 25,571
Notes payable	$ 37,000	$ 37,000	$ 145,500	$ 145,500
Long-term debt, including current maturities	$ 707,555	$ 722,697	$ 645,446	$ 663,162

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 included 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

In December 2007, the Rupert and Glenns Ferry partnerships, in which the Company has 50 percent interests, impaired the carrying amounts of their property, plant and equipment to reflect the partnerships assessment of the recoverability of their respective carrying amounts. The Company accounts for its investments in these partnerships using the equity method of accounting. Accordingly, the Company s carrying amounts for investments in these partnerships was reduced by $3.9 million to reflect the increased losses from the partnerships impairment charges. In addition, the Company wrote off $0.6 million of net goodwill impairment directly related to the Company s investments in the partnerships. At December 31, 2007, the Company s remaining carrying amount for these partnership investments was nominal. The Company s investment in the Rupert and Glenns Ferry partnership is included in the Power generation segment.

During September 2007, the Company assessed the recoverability of the carrying value of the Ontario power plant due to the pending thermal host contract expiration without a long-term extension. The carrying amount of the assets tested for impairment was $1.3 million. The assessment resulted in an impairment charge of $1.3 million, primarily for net property, plant and equipment and intangible assets. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. In addition, $1.4 million has been accrued for a contract termination payment and other related costs. These charges are included as a component of Operating expenses on the accompanying Consolidated Statement of Income. Operating results from the Ontario plant are included in the Power generation segment.

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. 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 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. For segment reporting, the development costs are included in Corporate results.

(12) OPERATING LEASES

The Company has entered into lease agreements relating to certain power plant land leases, a compressor lease, vehicle leases and office facility leases. Rental expense incurred under these operating leases was $1.5 million, $1.5 million and $0.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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

2008	$	2,597
2009		2,101
2010		1,073
2011		1,041
2012		943
Thereafter		9,140
	$	16,895

(13) INCOME TAXES

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

	2007		2006		2005	
	(in thousands)					
Current:						
Federal	$	14,111	$	155	$	24,601
State		(1,993)		(479)		620
Foreign		2,114		893		605
		14,232		569		25,826
Deferred:						
Federal		29,216		32,305		(8,743)
State		2,485		1,222		276
Tax credit amortization		(292)		(294)		(315)
		31,409		33,233		(8,782)
	$	45,641	$	33,802	$	17,044

Foreign taxes represent income taxes incurred through the Company s Canadian activities.

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

Years ended December 31,	2007	2006
	(in thousands)	
Deferred tax assets, current:		
Asset valuation reserves	$ 1,609	$ 1,474
Mining development and oil exploration	373	333
Unbilled revenue	1,480	1,694
Deferred costs	962	3,066
Employee benefits	3,470	1,883
Items of other comprehensive income	6,606	26
Derivative fair value adjustments	250	216
Other	97	30
	14,847	8,722
Deferred tax liabilities, current:		
Prepaid expenses	1,890	1,257
Derivative fair value adjustments	1,649	15
Items of other comprehensive income	1,601	5,238
Other	5,195	3,427
	10,335	9,937
Net deferred tax asset (liability), current	$ 4,512	$ (1,215)
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 2,866	$ 2,534
Mining development and oil exploration	73	55
Employee benefits	14,991	17,241
Regulatory asset	5,487	1,532
Deferred revenue	467	621
Deferred costs	395	700
State net operating loss	1,272	342
Items of other comprehensive income	6,400	4,967
Foreign tax credit carryover	3,304	1,530
Net operating loss (net of valuation allowance)	7,846	12,956
Asset impairment	58,819	57,659
Derivative fair value adjustment	203	183
Other	5,703	4,052
	107,826	104,372
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	213,313	185,237
Employee benefits		6,969
Regulatory liability	13,589	4,049
Mining development and oil exploration	84,844	72,249
Deferred costs	3,669	2,371
Derivative fair value adjustments	146	
Items of other comprehensive income		968
Other		6,861
	315,561	278,704
Net deferred tax liability, non-current	$ 207,735	$ 174,332
Net deferred tax liability	$ 203,223	$ 175,547

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

	2007 (in thousands)
Net change in deferred income tax liability from the preceding table	$ 27,676
Deferred taxes associated with other comprehensive loss	12,482
Deferred taxes related to net operating loss from acquisitions	(1,699)
Deferred taxes related to regulatory assets and liabilities	(4,568)
Other	(2,482)
Deferred income tax expense for the period	$ 31,409

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

	2007	2006	2005
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	0.2	0.4	1.2
Amortization of excess deferred and investment tax credits	(0.3)	(0.5)	(0.8)
Percentage depletion in excess of cost	(1.0)	(1.2)	(2.0)
Equity AFUDC	(1.1)	(0.9)	(0.3)
Goodwill impairment			1.2
IRS exam tax adjustment*		(2.4)	
State exam tax adjustment**	(0.5)		
Other	(1.0)	0.9	(0.1)
	31.3%	31.3%	34.2%

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* 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.

** As a result of the settlement of a state tax exam of the tax years 2001-2003 with respect to certain tax positions taken by the Company, a tax benefit of approximately $0.7 million (net of the federal tax effect) was recorded in 2007.

At December 31, 2007, 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
$ 1,374	2012
1,464	2018
1,069	2019
5,544	2021
17,146	2022
3,104	2023
230	2026

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As of December 31, 2007, 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.

FIN 48

The Company adopted the provisions of FIN 48 on January 1, 2007. 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. As a result of the implementation of FIN 48 the Company recognized an approximate $0.7 million benefit from a decrease in the liability for unrecognized tax benefits. This benefit was accounted for as an adjustment to the January 1, 2007 balance of retained earnings.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period (in thousands):

Unrecognized tax benefits January 1, 2007	$	72,583
Additions for prior year tax positions		4,719
Reductions for prior year tax positions		(46)
Additions for current year tax positions		623
Reductions for current year tax positions		
Settlements		(2,109)
Reductions to unrecognized tax benefits as a result of a lapse of the applicable statute of limitations		
Unrecognized tax benefits December 31, 2007	$	75,770

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $2.8 million.

It is the Company s continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2007, 2006 and 2005, the Company recognized approximately $0.1 million, $0.4 million and $0.5 million, respectively in interest. The Company had approximately $1.3 million and $0.7 million accrued for interest at December 31, 2007 and 2006, respectively.

The Company files income tax returns in the U.S. federal jurisdiction, various state jurisdictions and Canada. The Company received notification from the Internal Revenue Service that the 2004, 2005 and 2006 tax years will be examined. The Company remains subject to examination by Canadian income tax authorities for tax years as early as 1999.

The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statute of limitations prior to December 31, 2008.

In 2005, Canadian income tax returns were filed 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, 2007, the Company had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward		Expiration Year
$	9	2009
	236	2010
	550	2011
	345	2012
	11	2013
	376	2014
	694	2015
	940	2016
	111	2017

(14) COMPREHENSIVE INCOME

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):

	2007 Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 3,513	$ (1,224)	$ 2,289
Fair value adjustment of derivatives designated as cash flow hedges	(58,603)	20,212	(38,391)
Reclassification adjustments of cash flow hedges settled and included in net income	14,228	(4,910)	9,318
Reclassification adjustments for cash flow hedges settled and included in regulatory assets	4,288	(1,497)	2,791
Comprehensive income (loss)	$ (36,574)	$ 12,581	$ (23,993)

	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)
Comprehensive income	$ 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
Comprehensive income (loss)	$ (3,401)	$ 1,178	$ (2,223)

Balances by classification included within Accumulated other comprehensive (loss) income on the accompanying Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of December 31, 2007	$ (18,178)	$ (6,115)	$ (215)	$ (24,508)
As of December 31, 2006	$ 8,119	$ (8,404)	$ (230)	$ (515)

(15) PROCEEDS RECEIVED ON INSURANCE CLAIMS

In late 2005 and the first half of 2006, the Company s Las Vegas II power plant experienced unplanned outages due to damage to three of its gas turbines and two of its steam turbines. The outages lasted approximately six months as repairs were made to the turbines. The Company filed insurance claims for reimbursement of repair expenditures and business interruption losses in the amount of approximately $11.1 million.

During 2006, the Company received insurance proceeds of approximately $4.3 million. Approximately $0.4 million was applied to reduce capitalized repair costs included in Property, plant and equipment on the accompanying Consolidated Balance Sheet and $2.2 million for repair costs and $1.7 million for business interruption were applied as a reduction to Operations and maintenance expense on the accompanying Consolidated Statement of Income. During December 2007, the Company and the insurance carrier agreed to an additional final settlement amount of approximately $3.4 million. The Company has provided for receipt of these proceeds with approximately $0.9 million being applied to reduce capitalized repair costs included in Property, plant and equipment on the accompanying Consolidated Balance Sheet and approximately $2.5 million as a reduction to Operations and maintenance expense on the accompanying Consolidated Statement of Income.

(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 (Loss) income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as Assets of discontinued operations and Liabilities of discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of Crude Oil Marketing and Transportation Assets

On January 5, 2006, the Company entered into a definitive agreement to sell the operating assets of BHER, 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 (loss) income from discontinued operations and net assets of the crude oil marketing and transportation business at December 31 were as follows (in thousands):

	2007		2006		2005	
Operating revenues	$	67	$	171,911	$	778,103
Pre-tax (loss) income from discontinued operations (including 2006 severance payments)	$	(1,799)	$	(3,018)	$	4,223
Pre-tax gain on sale of assets				13,659		
Income tax benefit (expense)		525		(3,832)		(1,255)
Net (loss) income from discontinued operations	$	(1,274)	$	6,809	$	2,968

	2007		2006	
Current assets	$	961	$	1,424
Property, plant and equipment				
Other non-current assets		91		
Current liabilities		(1,207)		(2,352)
Other non-current liabilities		(344)		(174)
Net (deficit) assets	$	(499)	$	(1,102)

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 $103.0 million.

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

	2006		2005	
Revenues	$		$	21,877
Pre-tax income (loss) from discontinued operations	$		$	3,978
Pre-tax loss on disposal				(7,490)
Income tax benefit		164		1,405
Net income (loss) from discontinued operations	$	164	$	(2,107)

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.

Net loss from the discontinued operations during the year ended December 31, was as follows (in thousands):

	2005	
Pre-tax loss from discontinued operations	$	(326)
Pre-tax loss on disposal		(39)
Income tax benefit		132
Net loss from discontinued operations	$	(233)

(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 vest at 20 percent per year and are fully vested after completion of 5 years of service. The Black Hills Corporation Plan matching contributions were $1.7 million for 2007, $1.5 million for 2006 and $1.5 million for 2005. The Cheyenne Light Retirement Savings Plan matching contributions were $0.3 million for 2007, $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 2007, $0.1 million for 2006 and $0.2 million for 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.

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

Plan Assets

Percentage of fair value of assets for the Company s Pension Plans at September 30:

	2007	2006
Domestic equity	50.7 %	50.3%
Foreign equity	26.1	25.3
Fixed income	20.9	15.6
Cash	2.3	8.8
Total	100.0%	100.0%

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

Asset Class	Target Allocation
Domestic equity	50%
Foreign equity	25%
Fixed Income	25%

Cash	0%

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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 2007 and expects it will not make contributions to the Plan in the 2008 fiscal year.

The Company made a $0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2007 and expects to make a $0.5 million contribution during the 2008 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 $0.8 million in 2008. 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 2007 fiscal year was an actuarial gain of approximately $1.7 million. The effect on 2008 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 2008. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the Employee Benefit Plan obligations and fair value of assets for 2007 and 2006, components of the net periodic expense for the years ended 2007, 2006 and 2005 and elements of accumulated other comprehensive income for 2007 and 2006.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
	(in thousands)					
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 77,471	$ 73,855	$ 19,843	$ 19,206	$ 14,042	$ 14,275
Service cost	2,745	2,596	410	349	539	654
Interest cost	4,517	4,165	1,157	1,079	828	813
Actuarial (gain) loss	(3,040)	(511)	(737)	11	(1,445)	(1,198)
Amendments						(300)
Benefits paid	(2,710)	(2,634)	(730)	(802)	(817)	(669)
Medicare Part D accrued					85	
Plan participant s contributions					494	467
Net increase (decrease)	1,512	3,616	100	637	(316)	(233)
Projected benefit obligation at end of year	$ 78,983	$ 77,471	$ 19,943	$ 19,843	$ 13,726	$ 14,042

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
			(in thousands)			
Beginning market value of						

plan assets	$ 65,990	$ 59,285	$	$	$	$
Investment income	11,318	8,189				
Contributions	510	1,150				
Benefits paid	(2,711)	(2,634)				
Ending market value of plan assets	$ 75,107	$ 65,990	$	$	$	$

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Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans (in thousands)		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007	2006	2007	2006
Regulatory asset	$ 2,998	$ 10,676	$	$	$	$ 141
Current liability	$	$	$ 765	$ 742	$ 286	$ 258
Non-current asset	$ 3,529	$	$	$	$	$
Non-current liability	$ 7,404	$ 11,481	$ 18,992	$ 18,920	$ 13,386	$ 13,644
Regulatory liability	$ 56	$	$	$	$ 1,682	$ 598

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007 (in thousands)	2006	2007	2006
Accumulated benefit obligation - BHC	$ 61,513	$ 60,214	$ 14,577	$ 14,274	$ 9,847	$ 9,922
Accumulated benefit obligation Cheyenne Light	$ 2,344	$ 1,754	$	$	$ 3,879	$ 4,120

Components of Net Periodic Expense

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2007	2006	2005	2007 (in thousands)	2006	2005	2007	2006	2005
Service cost	$ 2,745	$ 2,596	$ 2,214	$ 410	$ 349	$ 344	$ 539	$ 654	$ 705
Interest cost	4,517	4,165	3,940	1,157	1,079	1,009	828	813	874
Expected return on assets	(5,493)	(4,988)	(4,628)						
Amortization of prior service cost	153	153	215	13	13	9		(24)	(24)
Amortization of transition obligation							60	150	150
Recognized net actuarial									

loss	507	906	1,183	713	797	629	(16)		100
Net periodic expense	$ 2,429	$ 2,832	$ 2,924	$ 2,293	$ 2,238	$ 1,991	$ 1,411	$ 1,593	$ 1,805

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 are as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2007	2006	2007 (in thousands)	2006	2007	2006
Net (loss) gain	$ (1,141)	$ (2,281)	$ (4,967)	$ (5,909)	$ 230	$ 65
Prior service cost	(192)	(224)	(11)	(20)		
Transition obligation					(28)	(34)
	$ (1,333)	$ (2,505)	$ (4,978)	$ (5,929)	$ 202	$ 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 2008 are as follows:

	Defined Benefit Pension Plans (in thousands)	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
Net loss (gain)	$	$ 370	$ 52
Prior service cost	106	8	
Transition obligation			39
Total net periodic benefit cost expected to be recognized during calendar year 2008	$ 106	$ 378	$ 91

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted-average assumptions used to determine benefit obligations:	2007	2006	2005	2007	2006	2005	2007	2006	2005
Discount rate	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%
Rate of increase in compensation levels	4.34%	4.31%	4.34%	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:	2007	2006	2005	2007	2006	2005	2007	2006	2005
Discount rate	5.95%	5.75%	6.00%	5.95%	5.75%	6.00%	5.95%	5.75%	6.00%

Expected long-term rate of return on assets*	8.50%	8.50%	9.00%	N/A	N/A	N/A	N/A	N/A	N/A
Rate of increase in compensation levels	4.31%	4.34%	4.39%	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 2008 net periodic pension cost.

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The healthcare trend rate assumption for 2007 fiscal year benefit obligation determination and 2008 fiscal year expense is a 10 percent increase for 2008 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2013. The healthcare cost trend rate assumption for the 2006 fiscal year benefit obligation determination and 2007 fiscal year expense was a 9 percent increase for 2007 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 $0.3 million or 24 percent and the accumulated periodic postretirement benefit obligation $2.6 million or 19 percent. A 1 percent decrease would reduce the service and interest cost by $0.3 million or 18 percent and the accumulated periodic postretirement benefit obligation $2.1 million or 15 percent.

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

			Non-pension Defined Benefit Postretirement Plans		
	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2008	$ 3,148	$ 765	$ 362	$ (75)	$ 287
2009	3,294	763	439	(85)	354
2010	3,514	786	545	(96)	449
2011	3,725	823	630	(108)	522
2012	3,912	841	708	(123)	585
2013-2017	24,912	5,536	4,763	(839)	3,924

(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 of 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 $10.9 million in 2007, $10.1 million in 2006 and $10.1 million in 2005.

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 the Company s capacity and energy will be transmitted by PacifiCorp: 17 MW in 2004-2006 and 50 MW in 2007-2023. Costs incurred under this agreement were $1.2 million in 2007, $0.4 million in 2006 and $0.4 million in 2005.

Long-Term Power Sales Agreements

The Company, through its subsidiaries, has the following significant long-term power sales contracts with non-affiliated third-parties:

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 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. As discussed under Las Vegas Cogeneration/Nevada Power Company Arbitration within this Note 18, pending approval by the PUCN this contract would be terminated and replaced by a new power purchase agreement that would be a tolling arrangement.

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 is 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.

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

The Company has a power purchase agreement to provide electric power to Public Service Company of New Mexico, a regulated electric and natural gas utility subsidiary of PNM. Under the terms of the agreement, the Company will provide the capacity and energy of the Valencia 149 MW simple-cycle gas turbine generation facility to be located near Albuquerque, New Mexico. The agreement is a customary tolling agreement, where the Company receives variable and fixed fees for the plant s availability and operation, and Public Service Company of New Mexico will be responsible for providing fuel for the operation. In addition, the agreement affords the Company favorable change of law and government impositions pass-throughs to Public Service Company of New Mexico. The duration of the power purchase agreement is 20 years. During the term of the agreement, Public Service Company of New Mexico is also provided an option to acquire a 50 percent equity interest in this project.

The Company has a power purchase agreement with Basin Electric for the supply of 80 MW of capacity and energy through 2012 and a separate agreement to receive 80 MW of capacity and energy through 2012. The agreements were entered into with Basin Electric to accommodate delivery of electricity to Cheyenne Light s service territory.

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 $0.3 million, $0.6 million and $0.6 million was charged to accretion expense for the years ended December 31, 2007, 2006 and 2005, respectively. Approximately $0.5 million, $0.5 million and $0.4 million was charged to depreciation expense for the years ended December 31, 2007, 2006 and 2005, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $14.8 million and $16.0 million at December 31, 2007 and 2006, respectively.

Legal Proceedings

Acquisition Earn-Out Litigation

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, 2007, $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. The parties retained an arbitrator who will direct the process and decide the Earn-Out issues presently in arbitration, according to the procedure stated in the Merger Agreement. A hearing before the arbitrator was held on December 7, 2007. No date for a final decision has been set by the arbitrator.

On February 8, 2008, the trial court entered its rulings on Motions for Summary Judgment filed by both parties. The court denied all of Plaintiff s motions. The court granted the Company s motions in part, and denied them, in part. Specifically, the trial court dismissed two claims for breach of contract, and all claims for breach of a covenant of good faith and fair dealing. Remaining for trial, therefore, are three claims for breach of contract, and a claim for spoliation of evidence. The Company continues to deny these claims and will vigorously defend them at a trial that commences on March 31, 2008.

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, which would be subject to a recoverability analysis under GAAP. If an adverse outcome and punitive damages were awarded, the punitive damages would be recorded as an expense. Any additional merger consideration that would be issued in the form of equity would also be dilutive to the Company s earnings on a per share basis.

Las Vegas Cogeneration/Nevada Power Company Arbitration

On March 16, 2007, Nevada Power filed a Demand for Arbitration pursuant to a Power Purchase Agreement dated May 27, 1992, (the Agreement) between Nevada Power and our wholly-owned subsidiary, Las Vegas Cogeneration Limited Partnership (LVC). Nevada Power asserts that LVC is in breach of its obligation under the Agreement to maintain a reliable fuel supply throughout the term of the Power Contract. On July 5, 2007, Nevada Power served an Amended Demand for Arbitration. The relief Nevada Power requests include: (1) A determination that the Agreement requires LVC to obtain and maintain firm, long-term fuel supply and transportation agreements for the full term of the Agreement; (2) A determination that LVC failed to honor this obligation; (3) A determination that LVC s failure to obtain and maintain firm fuel supply and transportation agreements constitutes a material breach of the Agreement; and (4) An order of specific performance requiring LVC to enter into long-term fuel supply and transportation agreements to cure the alleged breach.

LVC denies all these claims and filed its response to the Demand for Arbitration, asserting the following defenses: (1) That Nevada Power failed to honor its contractual obligation to properly negotiate in good faith before filing the Demand for Arbitration; (2) That LVC has complied with its obligations relating to fuel supply and transportation; and (3) That numerous other affirmative defenses preclude Nevada Power from receiving the relief requested.

On December 4, 2007, the parties reached a tentative agreement, which would result in the dismissal of arbitration proceedings. The proposed settlement agreement was filed with the PUCN on December 14, 2007. The PUCN must approve the settlement in order for it to become effective. If approved, the existing structure of Las Vegas I as a qualifying facility under federal law, together with existing contracts with Nevada Power, would be terminated. Las Vegas I would file with FERC to become an exempt wholesale generator with authority to sell power at market-based rates. Las Vegas I and Nevada Power reached agreement on the terms of a new Power Purchase Agreement that will replace the existing firm fuel supply and transportation agreements. The new Power Purchase Agreement likewise is subject to approval by the PUCN. On February 19, 2008, the Staff of the PUCN filed with the PUCN a written stipulation, setting forth the agreement, signed by all parties to the docket with respect to the relief and approvals requested from PUCN. Although not obligated to do so, in light of the stipulation, the Commission could approve the docket without further hearing. Alternatively, the PUCN could review the stipulation at the hearing currently set for March 10, 2008 and issue a written decision thereafter.

FERC Compliance Investigation

During 2007, following an internal review of natural gas marketing activities conducted within the Non-regulated energy group, the Company identified possible instances of noncompliance with regulatory requirements applicable to those activities. The Company has notified the staff of FERC of its findings. The Company has also evaluated recent public announcements of civil penalties ranging from $0.3 million to $7.0 million that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on the Company. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, the final resolution of these matters could have a material impact on the consolidated net income of any particular period, but is not expected to have a material impact upon the Company s overall consolidated financial position.

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 $169.0 million, $141.0 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, 2007, the Company had the following guarantees in place (in thousands):

Nature of Guarantee		Outstanding at December 31, 2007	Year Expiring
Guarantee obligations under the Wygen I Plant Lease	$	111,018	2008
Guarantee obligations of Enserco under an agency agreement		7,000	2008
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
Guarantee for obligations and damages, if any, due by Valencia under a power purchase agreement with Public Service Company of New Mexico		12,000	2028
Indemnification for subsidiary reclamation/surety bonds		4,014	Ongoing
	$	169,032	

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 Wygen I 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, 2007, 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 intends to refinance this indebtedness with other long-term financing prior to maturity.

The Company has guaranteed up to $7.0 million of the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $100.0 million of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The guarantee expires in June 2008.

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.

The Company has guaranteed the obligations and damages, if any, due by Valencia under a power purchase agreement with Public Service Company of New Mexico for up to $12.0 million. The guarantee expires in 2028.

In addition, at December 31, 2007, the Company had guarantees in place totaling approximately $4.0 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, 2007, substantially all of the Company s operations and assets are located within the United States.

The Company conducts its operations through the following six reporting segments:

Utilities group (previously referred to as Retail Services)

Electric utility, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; and

Electric and gas utility, which supplies electric and gas utility service to Cheyenne, Wyoming and vicinity.

Non-regulated energy group (previously referred to as Wholesale Energy)

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 with power plants concentrated in Colorado, Nevada, New Mexico, Wyoming and California;

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 primarily in the western and central regions of the United States and Canada.

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.

December 31:	2007 (in thousands)	2006
Total assets		
Utilities:		
Electric utility	$ 493,817	$ 474,164
Electric and gas utility	336,273	266,659
Non-regulated energy:		
Oil and gas	432,839	400,476
Power generation	724,799	702,137
Coal mining	58,024	58,584
Energy marketing	383,617	324,546
Corporate	42,445	16,686
Discontinued operations	1,052	1,424
Total assets	$ 2,472,866	$ 2,244,676
Capital expenditures and asset acquisitions		
Utilities:		
Electric utility	$ 35,743	$ 24,992
Electric and gas utility	69,220	107,348
Non-regulated energy:		
Oil and gas	72,153	158,846
Power generation	62,447	8,557
Coal mining	4,991	5,807
Energy marketing	177	928
Corporate	22,316	1,972
Total capital expenditures and asset acquisitions	$ 267,047	$ 308,450
Property, plant and equipment		
Utilities:		
Electric utility	$ 695,100	$ 675,635
Electric and gas utility	315,825	247,255
Non-regulated energy:		
Oil and gas	559,394	486,596
Power generation	798,358	737,483
Coal mining	86,721	82,458
Energy marketing	2,389	2,243
Corporate	32,778	10,726
Total property, plant and equipment	$ 2,490,565	$ 2,242,396

December 31:	2007 (in thousands)	2006	2005
External operating revenues			
Utilities:			
Electric utility	$ 197,804	$ 190,814	$ 186,806
Electric and gas utility	103,710	132,189	110,875
Non-regulated energy:			
Oil and gas	101,522	95,078	87,536
Power generation	159,734	154,985	158,399
Coal mining	26,154	22,405	21,376
Energy marketing	93,836	51,231	37,722
Corporate		46	771
Total external operating revenues	$ 682,760	$ 646,748	$ 603,485
Intersegment operating revenues			
Utilities:			
Electric utility	$ 1,897	$ 2,352	$ 2,199
Non-regulated energy:			
Oil and gas			13
Coal mining	16,334	13,877	12,901
Intersegment eliminations	(5,077)	(6,095)	(5,057)
Total intersegment operating revenues[(a)]	$ 13,154	$ 10,134	$ 10,056

(a) In accordance with the provisions of SFAS 71, intercompany fuel sales to the Company s regulated utilities are not eliminated.

December 31:	2007	2006	2005
Depreciation, depletion and amortization			
Utilities:			
Electric utility	$ 20,763	$ 19,801	$ 19,543
Electric and gas utility	4,754	5,415	4,532
Non-regulated energy:			
Oil and gas	34,192	30,176	22,114
Power generation	32,984	31,907	35,583
Coal mining	5,016	5,211	4,366
Energy marketing	813	512	355
Corporate	1,178	1,061	1,623
Total depreciation, depletion and amortization	$ 99,700	$ 94,083	$ 88,116
Operating income (loss)			
Utilities:			
Electric utility	$ 47,514	$ 40,002	$ 36,044
Electric and gas utility	5,798	5,954	3,053
Non-regulated energy:			
Oil and gas	25,437	26,088	31,605
Power generation	56,432	58,817	(2,154)
Coal mining	6,177	6,916	7,892
Energy marketing	51,769	24,008	19,198
Corporate	(13,576)	(8,399)	(13,787)
Intersegment eliminations		(714)	
Total operating income	$ 179,551	$ 152,672	$ 81,851

December 31:	2007 (in thousands)	2006	2005
Interest income			
Utilities:			
Electric utility	$ 7,188	$ 2,970	$ 258
Electric and gas utility	94	238	613
Non-regulated energy:			
Oil and gas	317	156	39
Power generation	20,224	17,986	20,914
Coal mining	2,074	1,858	1,304
Energy marketing	3,308	1,859	1,157
Corporate	60,138	61,312	23,597
Intersegment eliminations	(89,734)	(84,598)	(46,165)
Total interest income	$ 3,609	$ 1,781	$ 1,717
Interest expense			
Utilities:			
Electric utility	$ 18,091	$ 14,769	$ 12,907
Electric and gas utility	2,921	1,407	708
Non-regulated energy:			
Oil and gas	8,974	7,120	3,922
Power generation	41,870	48,709	45,069
Coal mining	390	427	
Energy marketing	1,177	2,139	1,498
Corporate	57,264	61,053	30,694
Intersegment eliminations	(89,734)	(84,598)	(46,165)
Total interest expense	$ 40,953	$ 51,026	$ 48,633
Income taxes			
Utilities:			
Electric utility	$ 12,568	$ 10,129	$ 5,743
Electric and gas utility	258	1,478	844
Non-regulated energy:			
Oil and gas	5,182	7,127	10,511
Power generation	10,589	8,612	(558)
Coal mining	2,091	2,819	2,641
Energy marketing	19,746	6,419	5,021
Corporate	(4,793)	(2,532)	(7,158)
Intersegment eliminations		(250)	
Total income taxes	$ 45,641	$ 33,802	$ 17,044
Income (loss) from continuing operations			
Utilities:			
Electric utility	$ 24,896	$ 18,724	$ 18,005
Electric and gas utility	6,737	5,464	2,114
Non-regulated energy:			
Oil and gas	12,706	12,736	17,905
Power generation	21,372	19,901	(12,524)[(b)]
Coal mining	6,107	5,877	6,947
Energy marketing	34,178	17,322	13,836
Corporate	(5,872)	(5,514)	(13,491)
Intersegment eliminations		(464)	
Total income from continuing operations	$ 100,124	$ 74,046	$ 32,792

(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

Aquila

On February 7, 2007, the Company entered into a definitive agreement with Aquila 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.

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. During October 2007, the shareholders of Great Plains and Aquila approved the merger. The purchase is also subject to regulatory approvals from the Missouri Public Service Commission, the Kansas Corporation Commission, the Colorado Public Utilities Commission, the Nebraska Public Service Commission, the Iowa Utilities Board and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions. As of February 29, 2008, the Company has obtained state regulatory approval for the transfer of ownership in Iowa, Nebraska and Colorado. On February 12, 2008, a hearing was held by the Kansas Corporation Commission on our joint application with Aquila. All the parties to the Kansas proceeding entered into a settlement which was presented at that hearing. A decision by the Kansas regulators is pending. Another party to the transaction, Great Plains, must obtain approval from regulators in the states of Missouri and Kansas, which is pending. At the federal level, the FERC has approved the acquisition of the Colorado Electric utility, and antitrust clearance has been obtained from the Federal Trade Commission.

In conjunction with the asset acquisition, on May 7, 2007, the Company entered into a senior unsecured $1.0 billion acquisition facility to provide funding for the Company s pending acquisition of Aquila assets. The acquisition facility is a committed facility to fund an acquisition term loan in a single draw in an amount of up to $1.0 billion. The commitment to fund the acquisition term loan expires on August 5, 2008. Upon funding of the loan, the loan termination date is February 5, 2009.

This transaction would add approximately 92,000 electric utility customers and 520,000 gas utility customers to the Company s utility operations.

The Company is capitalizing certain incremental acquisition costs incurred related to this pending acquisition. Amounts capitalized at December 31, 2007 were approximately $19.1 million. In addition, the Company has expensed certain integration-related costs of approximately $7.4 million for the twelve months ended December 31, 2007.

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

BHEP has operating and non-operating interests in 1,236 developed oil and gas wells in ten states and holds leases on approximately 436,000 net acres.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31, (in thousands):

	2007	2006	2005
Acquisition of properties:			
Proved	$	$ 64,265	$ 4,110
Unproved		19,336	6,779
Exploration costs	7,250	21,752	7,194
Development costs	62,104	53,080	58,669
Asset retirement obligations incurred	1,934	4,468	277
	$ 71,288	$ 162,901	$ 77,029

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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, 2007, 2006 and 2005, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Cawley, Gillespie & Associates, Inc., an independent engineering company selected by the Company for the year 2007. Estimates for 2006 and 2005 are based on reserve reports by Ralph E. Davis Associates, Inc. Such reserve estimates are inherently imprecise and may be subject to 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.

	2007		2006		2005	
	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	5,723	164,754	6,835	128,573	5,239	141,983
Production	(409)	(11,697)	(401)	(11,512)	(396)	(10,854)
Additions acquisitions				59,813		6,081
Additions extensions and discoveries	373	21,318	118	12,524	1,548	15,675
Revisions to previous estimates	120	(1,411)	(829)	(24,644)	444	(24,312)
Balance at end of year	5,807	172,964	5,723	164,754	6,835	128,573
Proved developed reserves at end of year included above	5,095	92,522	4,723	87,891	4,694	80,959
Year-end prices (NYMEX)	$ 95.98	$ 6.80	$ 61.05	$ 5.52	$ 61.04	$ 11.23
Year-end prices (average well-head)	$ 83.23	$ 5.88	$ 52.06	$ 5.34	$ 58.52	$ 9.06

The majority of the reserve additions are the results of booking infill locations in our operated New Mexico East Blanco Field, non-operated Montana St. Joe Road Field, non-operated Oklahoma Arkoma Basin, and non-operated Wyoming Madden Deep Unit. These bookings resulted in 77 percent of the additions. Also, another 11 percent of additions were a direct result of our exploration drilling in the South Antelope Prospect in North Dakota and Cole Creek Prospect in Wyoming.

The 2007 reserve reconciliation reflects a 0.7 Bcfe downward revision to previous estimates. The downward revision was slight; however, there were varying components that make up the outcome. The improved performance and better modeling of the gas/oil ratio in the Finn-Shurley field resulted in a positive revision. Also, the increase in natural gas and oil prices as of December 31, 2007 compared to December 31, 2006 contributed to a positive revision. These positive revisions were offset by eliminating some horizontal (Many Canyons Field) and vertical (shallow San Jose production zone) locations in the San Juan basin based on more recent performance data.

Capitalized Costs

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

	2007	2006	2005
Unproved oil and gas properties	$ 37,459	$ 36,936	$ 15,390
Proved oil and gas properties	475,061	409,984	271,881
	512,520	446,920	287,271
Accumulated depreciation, depletion & amortization and valuation allowances	(141,780)	(112,020)	(85,488)
Net capitalized costs	$ 370,740	$ 334,900	$ 201,783

Results of Operations

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

	2007	2006	2005
Revenues			
Sales	$ 101,286	$ 94,682	$ 87,235
Production costs	28,824	27,487	23,897
Depreciation, depletion & amortization and valuation provisions	31,212	27,420	20,396
	60,036	54,907	44,293
Income tax expense	5,303	7,180	10,412
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ 35,947	$ 32,595	$ 32,530

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):

	2007	2006	2005
Future cash inflows	$ 1,544,175	$ 1,238,962	$ 1,655,378
Future production costs	(438,314)	(435,314)	(502,780)
Future development costs	(140,118)	(118,266)	(84,049)
Future income tax expense	(284,678)	(184,373)	(324,306)
Future net cash flows	681,065	501,009	744,243
10 percent annual discount for estimated timing of cash flows	(358,167)	(233,484)	(346,774)
Standardized measure of discounted future net cash flows	$ 322,898	$ 267,525	$ 397,469

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):

	2007	2006	2005
Standardized measure beginning of year	$ 267,525	$ 397,469	$ 309,199
Sales and transfers of oil and gas produced, net of production costs	(63,659)	(64,367)	(70,400)
Net changes in prices and production costs	107,920	(233,599)	301,055
Extensions, discoveries and improved recovery, less related costs	34,771	30,114	71,544
Net changes in future development costs	45,127	38,256	(4,302)
Revisions of previous quantity estimates, changes in production rates, changes in timing and other	(71,685)	(106,124)	(185,878)
Accretion of discount	33,852	56,002	39,445
Net change in income taxes	(30,953)	91,556	(77,306)
Purchases of reserves		58,218	14,112
Standardized measure end of year	$ 322,898	$ 267,525	$ 397,469

Changes in the standardized measure from revisions of previous quantity estimates, changes in production rates, changes in timing and other, are driven by reserve revisions, modifications of production profiles and timing of future development. For 2007, we had minimal net reserve revisions to prior estimates. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting, service availability, etc.

(23) **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 2007 and 2006.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2007				
Operating revenues	$ 186,533	$ 163,943	$ 162,354	$ 183,084
Operating income	55,955	45,316	32,558	45,722
Income from continuing operations	32,500	25,231	17,642	24,751
Loss from discontinued operations, net of taxes	(47)	(133)	(178)	(994)
Net income	32,453	25,098	17,464	23,757
Net income available for common stock	32,453	25,098	17,464	23,757
Earnings (loss) per common share:				
Basic -				
Continuing operations	$ 0.92	$ 0.67	$ 0.47	$ 0.66
Discontinued operations				(0.03)
Total	$ 0.92	$ 0.67	$ 0.47	$ 0.63
Diluted -				
Continuing operations	$ 0.91	$ 0.66	$ 0.46	$ 0.65
Discontinued operations				(0.03)
Total	$ 0.91	$ 0.66	$ 0.46	$ 0.62
Dividends paid per share	$ 0.34	$ 0.34	$ 0.34	$ 0.35
Common stock prices				
High	$ 39.63	$ 42.59	$ 44.48	$ 45.41
Low	$ 35.40	$ 36.86	$ 36.84	$ 40.21

	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

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, who is also currently serving as interim 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, 2007. Based on his evaluation, he has concluded that our disclosure controls and procedures are effective.

Internal control over financial reporting

Management s Report on Internal Control over Financial Reporting is presented on page 92 of this Annual Report on Form 10-K.

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 20, 2008.

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 20, 2008.

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 20, 2008.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2007 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 (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders[1]	679,730 [2]	$ 29.49[2]	982,029 [3]
Equity compensation plans not approved by security holders			
Total	679,730	$ 29.49	982,029

[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 140,303 full value awards outstanding as of December 31, 2007, 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, 114,573 shares of unvested restricted stock were outstanding as of December 31, 2007, 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 20, 2008.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement for the Annual Shareholder s Meeting to be held May 20, 2008.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Black Hills Corporation

Rapid City, South Dakota

We have audited the consolidated financial statements of Black Hills Corporation and subsidiaries (the Corporation) as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and the Corporation s internal control over financial reporting as of December 31, 2007, and have issued our reports thereon dated February 27, 2008 (which report on the consolidated financial statements expresses an unqualified opinion, and includes an explanatory paragraph relating to the adoption of new accounting standards); such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Corporation listed in Item 15. This 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, MN

February 27, 2008

(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, 2007, 2006 and 2005.

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, 2007, 2006 AND 2005

		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:					
2007	$ 4,202	$ 2,896	$ 354	$ (2,864)	$ 4,588
2006	4,685	2,811	(5)	(3,289)	4,202
2005	4,196	(277)	1,778	(1,012)	4,685

(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).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant s Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated December 11, 2007 (filed as Exhibit 3 to the Registrant s Form 8-K filed December 17, 2007).
3.3*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as Exhibit 4.4 to the Registrant s Form 8-K filed on December 26, 2000).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant s Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant s Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant s Form 10-K for 2000).
10.1*	Coal Leases between WRDC and the Federal Government
	Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant s Form S-7, File No. 2-60755)
	Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant s Form 10-K for 1989)
	Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant s Form S-7, File No. 2-60755)
	Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant s Form 10-K for 1989)
	Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant s Form S-7, File No. 2-60755)
	Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant s Form 10-K for 1989).
10.2*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant s Form 10-K for 1997).

10.3*	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant s Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant s Form 10-K for 2002).
10.4*	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).
10.5*	Black Hills Corporation Nonqualified Deferred Compensation Plan dated June 1, 1999 (filed as Exhibit 10.13 to the Registrant s Form 10-K for 2000). First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan dated April 29, 2003 (filed as Exhibit 10.6 to the Registrant s Form 10-K for 2003).
10.6*	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant s Form 10-K for 1997).
10.7*	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant s Form 10-K for 2000).
10.8*	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant s Form 10-K for 2001).
10.9*	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant s Proxy Statement filed April 13, 2005).
10.10*	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on July 11, 2005).
10.11	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.12*	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on July 11, 2005).
10.13	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.14*	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant s Form 8-K filed on July 11, 2005).
10.15	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.16*	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant s Form 8-K filed on July 11, 2005).
10.17	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.18*	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant s Form 8-K filed on September 3, 2004).

10.19*	Change in Control Agreement dated June 30, 2005 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on July 1, 2005).
10.20*	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on July 1, 2005).
10.21*	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant s Form 10-K for 1997). First Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.13 to the Registrant s Form 10-K for 2003). Second Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.14 to the Registrant s Form 10-K for 2003). Third Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on June 2, 2005). Fourth Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.18 to the Registrant s Form 10-K for 2006).
10.22	Fifth Amendment to the Outside Directors Stock Based Compensation Plan.
10.23*	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant s Form 10-K for 1998).
10.24*	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).
10.25*	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).
10.26*	Severance and Release Agreement between Mark T. Thies and Black Hills Corporation (filed as Exhibit 10 to the Registrant s Form 8-K filed January 18, 2008).
10.27*	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).
10.28*	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).
10.29*	Securities Purchase Agreement dated as of February 14, 2007, by and among Black Hills Corporation and the investors named therein (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on February 22, 2007).
10.30*	Registration Rights Agreement dated as of February 22, 2007, by and among Black Hills Corporation and the investors named therein (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on February 22, 2007).

10.31*	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). First Amendment to the Credit Agreement, dated as of May 12, 2006 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on March 19, 2007). Second Amendment to the Credit Agreement, dated as of March 13, 2007 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on March 19, 2007).
10.32*	Second Amended and Restated Credit Agreement (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). First Amendment to the Credit Agreement effective November 30, 2006 (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on May 16, 2007). Second Amendment to the Credit Agreement effective May 11, 2007 (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on May 16, 2007).
10.33*	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).
10.34*	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).
10.35*	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).
10.36*	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).
10.37*	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).
10.38*	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).

10.39*	Credit Agreement dated as of May 7, 2007 among Black Hills Corporation as Borrower, ABN AMRO Bank N.V., as administrative agent, sole bookrunner and co-arranger, BMO Capital Markets, as syndication agent and co-arranger, Credit Suisse Securities (USA) LLC, as syndication agent and co-arranger, Union Bank of California, N.A., as syndication agent and co-arranger, and the Financial Institutions party thereto, as Banks (filed as Exhibit 10.3 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2007).
10.40*	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).
10.41*	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).
10.42*	Mutual Notice of Extension provided as of January 31, 2008, by and among Black Hills Corporation, Aquila, Inc., and Great Plains Energy Incorporated (filed as Exhibit 10 to the Registrant s Form 8-K filed on February 1, 2008).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors Consent.
23.2	Consent of Petroleum Engineer and Geologist.
31	Certification pursuant to Rule 13a 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
32	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.

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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: February 29, 2008

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 and acting interim Principal Financial and Accounting Officer	February 29, 2008
/S/ DAVID C. EBERTZ David C. Ebertz	Director	February 29, 2008
/S/ JACK W. EUGSTER Jack W. Eugster	Director	February 29, 2008
/S/ JOHN R. HOWARD John R. Howard	Director	February 29, 2008
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	February 29, 2008
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	February 29, 2008
/S/ GARY L. PECHOTA Gary L. Pechota	Director	February 29, 2008
/S/ WARREN L. ROBINSON Warren L. Robinson	Director	February 29, 2008
/S/ JOHN B. VERING John B. Vering	Director	February 29, 2008
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 29, 2008

INDEX TO 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).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant s Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated December 11, 2007 (filed as Exhibit 3 to the Registrant s Form 8-K filed December 17, 2007).
3.3*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as Exhibit 4.4 to the Registrant s Form 8-K filed on December 26, 2000).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant s Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant s Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant s Form 10-K for 2000).

10.1*	Coal Leases between WRDC and the Federal Government Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant s Form S-7, File No. 2-60755) Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant s Form 10-K for 1989) Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant s Form S-7, File No. 2-60755) Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant s Form 10-K for 1989) Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant s Form S-7, File No. 2-60755) Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant s Form 10-K for 1989).
10.2*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant s Form 10-K for 1997).
10.3*	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant s Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant s Form 10-K for 2002).
10.4*	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).
10.5*	Black Hills Corporation Nonqualified Deferred Compensation Plan dated June 1, 1999 (filed as Exhibit 10.13 to the Registrant s Form 10-K for 2000). First Amendment to the Black Hills Corporation Nonqualified Deferred Compensation Plan dated April 29, 2003 (filed as Exhibit 10.6 to the Registrant s Form 10-K for 2003).
10.6*	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant s Form 10-K for 1997).
10.7*	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant s Form 10-K for 2000).
10.8*	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant s Form 10-K for 2001).
10.9*	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant s Proxy Statement filed April 13, 2005).
10.10*	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on July 11, 2005).
10.11	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.

10.12*	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on July 11, 2005).
10.13	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.14*	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant s Form 8-K filed on July 11, 2005).
10.15	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.16*	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant s Form 8-K filed on July 11, 2005).
10.17	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007.
10.18*	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant s Form 8-K filed on September 3, 2004).
10.19*	Change in Control Agreement dated June 30, 2005 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on July 1, 2005).
10.20*	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on July 1, 2005).
10.21*	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant s Form 10-K for 1997). First Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.13 to the Registrant s Form 10-K for 2003). Second Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.14 to the Registrant s Form 10-K for 2003). Third Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on June 2, 2005). Fourth Amendment to the Outside Directors Stock Based Compensation Plan (filed as Exhibit 10.18 to the Registrant s Form 10-K for 2006).
10.22	Fifth Amendment to the Outside Directors Stock Based Compensation Plan.
10.23*	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant s Form 10-K for 1998).
10.24*	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).

10.25*	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).
10.26*	Severance and Release Agreement between Mark T. Thies and Black Hills Corporation (filed as Exhibit 10 to the Registrant s Form 8-K filed January 18, 2008).
10.27*	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).
10.28*	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).
10.29*	Securities Purchase Agreement dated as of February 14, 2007, by and among Black Hills Corporation and the investors named therein (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on February 22, 2007).
10.30*	Registration Rights Agreement dated as of February 22, 2007, by and among Black Hills Corporation and the investors named therein (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on February 22, 2007).
10.31*	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). First Amendment to the Credit Agreement, dated as of May 12, 2006 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on March 19, 2007). Second Amendment to the Credit Agreement, dated as of March 13, 2007 among Black Hills Corporation, as Borrower, ABN AMRO Bank N.V., in its capacity as agent for the Banks under the Credit Agreement, and as a Bank, and the other Banks party thereto (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on March 19, 2007).

10.32*	Second Amended and Restated Credit Agreement (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). First Amendment to the Credit Agreement effective November 30, 2006 (filed as Exhibit 10.2 to the Registrant s Form 8-K filed on May 16, 2007). Second Amendment to the Credit Agreement effective May 11, 2007 (filed as Exhibit 10.1 to the Registrant s Form 8-K filed on May 16, 2007).
10.33*	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).
10.34*	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).
10.35*	Amendment No. 1 dated as of December 20, 2001 to Agreement for Leasedated as of July 20, 2001 between Wygen Funding, Limited Partnership asOwner and Black Hills Generation, Inc., as Agent (filed as Exhibit 10.32 tothe Registrant s Form 10-K for 2001).
10.36*	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).
10.37*	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).
10.38*	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).
10.39*	Credit Agreement dated as of May 7, 2007 among Black Hills Corporation as Borrower, ABN AMRO Bank N.V., as administrative agent, sole bookrunner and co-arranger, BMO Capital Markets, as syndication agent and co-arranger, Credit Suisse Securities (USA) LLC, as syndication agent and co-arranger, Union Bank of California, N.A., as syndication agent and co-arranger, and the Financial Institutions party thereto, as Banks (filed as Exhibit 10.3 to the Registrant s Form 10-Q for the quarterly period ended June 30, 2007).
10.40*	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).
10.41*	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).
10.42*	Mutual Notice of Extension provided as of January 31, 2008, by and among Black Hills Corporation, Aquila, Inc., and Great Plains Energy Incorporated (filed as Exhibit 10 to the Registrant s Form 8-K filed on February 1, 2008).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors Consent.
23.2	Consent of Petroleum Engineer and Geologist.

31	Certification pursuant to Rule 13a 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
32	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Previously filed as part of the filing indicated and incorporated by reference herein.
Indicates a board of director or management compensatory plan.