BLACK HILLS CORP /SD/
Form 10-K
March 02, 2009

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, 2008

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, 2008 $1,218,945,373

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, 2009
Common stock, $1.00 par value	38,699,227 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 2009 Annual Meeting of Stockholders to be held on May 19, 2009, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Acquisition Facility	Our $1.0 billion single-draw, senior unsecured facility from which a $383 million draw was used to provide part of the funding for our Aquila Transaction
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila
ARO	Asset Retirement Obligations
BART	Best Available Retrofit Technology
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
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
BHER	Black Hills Energy Resources, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Corporation Plan	Black Hills Corporation Retirement Savings Plan
Black Hills Energy	The name used to conduct the business of Black Hills Utility Holdings, Inc. including the gas and electric utility properties acquired from Aquila
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of the Company that was formerly known as Black Hills Energy, Inc.
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of the Company
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of the Company formed to acquire and own the utility properties acquired from Aquila, all which are now doing business as Black Hills Energy
Black Hills Wyoming	Black Hills Wyoming, Inc., a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
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
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Colorado electric utility properties acquired from Aquila
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Colorado gas utility properties acquired from Aquila
CPUC	Colorado Public Utilities Commission

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CT	Combustion turbine
Dth	Dekatherms
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings
Enserco Facility	The $300 million uncommitted, secured line of credit that supports Enserco s marketing and trading operations, which currently expires May 8, 2009
EPA	U. S. Environmental Protection Agency
EPA 2005	Energy Policy Act of 2005
ERISA	Employee Retirement Income Security Act
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Fortis	Fortis Capital Group
GAAP	Accounting principles generally accepted in the United States
GCA	Gas Cost Adjustment
Great Plains	Great Plains Energy Incorporated
Hastings	Hastings Fund Management Ltd
IGCC	Integrated Gasification Combined Cycle
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
Indeck	Indeck Capital, Inc.
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Iowa gas utility properties acquired from Aquila
IPP	Independent Power Production
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants to affiliates of Hastings and IIF
IRS	Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Kansas gas utility properties acquired from Aquila
KCC	Kansas Corporation Commission
KWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
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 Co., a public utility division of MDU Resources Group, Inc.
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
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings, formed to hold the Nebraska gas utility properties acquired from Aquila
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NYMEX	New York Mercantile Exchange
PCA	Power Cost Adjustment
PGA	Purchase Gas Adjustment
PSCo	Public Service Company of Colorado
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RCRA	Resource Conservation and Recovery Act
RTO	Regional Transmission Organization
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
SO_2	Sulfur Dioxide
S&P	Standard & Poor s, a division of The McGraw-Hill Companies, Inc.
Valencia	Valencia Power, LLC, a former subsidiary of Black Hills Non-regulated Holdings that was sold as part of our IPP Transaction
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 Non-regulated Holdings

ACCOUNTING PRONOUNCEMENTS

APB	Accounting Principles Board
APB 25	APB Opinion No. 25, Accounting for Stock Issued to Employees
ARB	Accounting Research Bulletin
ARB No. 51	ARB No. 51, Consolidated Financial Statements
EITF	Emerging Issues Task Force
EITF 04-6	EITF Issue No. 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry
EITF 87-24	EITF 87-24, Allocation of Interest to Discontinued Operations
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
FIN 39	FASB Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts an Interpretation of APB Opinion No. 10 and FASB Statement No. 105
FIN 45	FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others
FIN 46	FASB Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 46(R)	FASB Interpretation No. 46, Consolidation of Variable Interest Entities Revised
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109
FSP	FASB Staff Position
FSP FAS 157-1	FSP FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurement for Purposes of Lease Classification or Measurement under Statement 13
FSP FAS 157-2	FSP FAS 157-2, Effective Date of FASB Statement No. 157
FSP FIN 39-1	FSP FIN 39-1, Amendment of FASB Interpretation No. 39
SEC Final Rule #33-8995	Modernization of Oil and Gas Reporting
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 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
SFAS 161	SFAS 161, Disclosure about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officer, Corporate Governance Guidelines of our Board of Directors and Policy for Independent Directors. The information contained on our website is not part of this document.

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC, as exhibits to our Annual Report on Form 10-K, the certifications required by Section 302 of the Sarbanes Oxley Act regarding the quality of our public disclosure. Our Chief Executive Officer certified to the New York Stock Exchange following our 2008 annual shareholder meeting that he was not aware of violations by us of the New York Stock Exchange corporate governance listing standards.

Each of the foregoing documents is available in print to any of our shareholders upon request by writing to Black Hills Corporation, Attention: Investor Relations, 625 Ninth Street, Rapid City, South Dakota 57701.

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 that 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:

Our ability to obtain adequate cost recovery for our 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 obtain permanent financing for the Aquila Transaction and other capital expenditures on reasonable terms;

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

Our ability to receive regulatory approval from the CPUC for our proposed construction of new power generation facilities for Colorado Electric;

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

Our ability to successfully maintain 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;

The timing, volatility and extent of changes in energy and commodity prices, supply or volume, the cost and availability of transportation of commodities, changes in interest or foreign exchange rates, and the demand for our services, any of which can affect our earnings, our financial liquidity and the underlying value of our assets;

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, or the possibility of reductions in our drilling program resulting from the current economic climate and commodity prices, which also may prevent us from maintaining production rates and replacing reserves for our oil and gas properties;

Our ability to accurately estimate demand from our customers for natural gas;

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;

The possibility that we may be required to take impairment charges under the SEC s full cost ceiling test for the accumulated costs of our natural gas and oil reserves;

Changes in business and financial reporting practices arising from the enactment of the EPA 2005 and subsequent rules and regulations promulgated thereunder;

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

Our ability to minimize losses related to defaults on amounts due from customers and counterparties, including counterparties to trading and other commercial transactions;

The amount of collateral required to be posted from time to time in our transactions;

Our ability to comply, or to make expenditures required to comply, with changes in laws and regulations, particularly those relating to taxation, safety and protection of the environment, and to recover those expenditures in customer rates, where applicable;

Our ability to recover our borrowing costs, including debt service costs, in our customer rates;

Liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;

Changes in state laws or regulations that could cause us to curtail our independent power production or exploration and production activities;

Weather and other natural phenomena;

Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, (ii) changing conditions in the capital and credit markets, which affect our ability to raise capital on favorable terms, and (iii) general economic and political conditions, including tax rates or policies and inflation rates;

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; and

Price risk due to marketable securities held as investments in benefit plans.

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

History and Organization

Black Hills Corporation, a South Dakota corporation (the Company, we, us, our), is a diversified energy company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, the Company began selling and marketing various forms of energy on an unregulated basis.

We operate principally in the United States with two major business groups: Utilities and Non-regulated Energy. Our Utilities Group is comprised of our Electric Utilities and Gas Utilities segments, and our Non-regulated Energy Group is comprised of our Oil and Gas, Power Generation, Coal Mining, and Energy Marketing segments, as shown below. At December 31, 2008, we had 2,122 employees, 686 of which were represented by union locals.

Business Group	**Financial Segment**
Utilities	Electric Utilities Gas Utilities
Non-regulated Energy	Oil and Gas Power Generation Coal Mining Energy Marketing

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light, a combination electric and gas utility, and its approximately 33,300 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 524,000 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities owns 630 MWs of generation and 7,909 miles of electric transmission and distribution lines, and our Gas Utilities owns 629 miles of intrastate gas transmission pipelines and 7,878 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated earnings from continuing operations of $43.9 million in the year ended December 31, 2008 and had total assets of $2.2 billion at December 31, 2008.

Prior to the third quarter of 2008, our Utilities Group consisted of two reporting segments: our Electric Utility segment (Black Hills Power) and our combination Electric and Gas Utility segment (Cheyenne Light). In the third quarter of 2008, we changed the reporting segments within our Utilities Group to reflect significant changes to our utility business resulting from the Aquila Transaction, through which we acquired four gas utility systems and one electric utility system.

Our Oil and Gas segment engages in the exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region. Our Coal Mining segment produces coal at our coal mine near Gillette, Wyoming, and our Energy Marketing segment markets natural gas, crude oil and related services, primarily in the Western and Mid-continent regions of the Unites States and Canada. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy primarily under long-term contracts. In 2008, we sold seven IPP plants previously reported in our Power Generation segment, which resulted in the operations of these plants being reported as discontinued operations.

Segment Financial Information

We discuss our business strategy and other prospective information in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding our business segments is incorporated herein by reference to Item 8 Financial Statements and Supplementary Data, particularly Note 20 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Business Group Overview

Utilities Group

We conduct electric utility operations and combination electric and gas utility operations through three subsidiaries: Black Hills Power (South Dakota, Wyoming and Montana), Cheyenne Light (Wyoming), and Colorado Electric (Colorado). Our Electric Utilities generate, transmit and distribute electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana. They also distribute natural gas to approximately 33,300 natural gas utility customers served by Cheyenne Light in Wyoming. Our electric generating facilities and purchased power contracts supply electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including affiliates.

We conduct natural gas utility operations on a state-by-state basis through our Colorado Gas, Iowa Gas, Kansas Gas and Nebraska Gas subsidiaries. Our Gas Utilities distribute natural gas to approximately 524,000 customers in Colorado, Iowa, Kansas and Nebraska. We also release excess capacity to pipelines and other pipeline customers when we do not need such pipeline capacity for our Gas Utilities customers.

Since our three electric utilities and our four natural gas utilities have similar economic characteristics, we aggregate our electric utility operations into the Electric Utilities segment and our gas utility operations into the Gas Utilities segment.

Electric Utilities Segment

Capacity and Demand

Uninterrupted system peak demands for the Electric Utilities for each of the last three years are listed below:

By Entity	System Peak Demand (in MW)					
	2008		2007		2006	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	409	407	430	361	415	331
Cheyenne Light	166	168	163	152	155	146
Colorado Electric[(a)]	306	298				

Total Electric Utilities	881	873	593	513	570	477

(a) For the period July 14, 2008 to December 31, 2008.

Regulated Power Plants

As of December 31, 2008, our Electric Utilities ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Gross Capacity (MW)	Year Installed
Black Hills Power[1]:					
Neil Simpson II	Coal	Gillette, WY	100	90.0	1995
Wyodak[2]	Coal	Gillette, WY	20	72.4	1978
Osage	Coal	Osage, WY	100	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100	21.8	1969
Neil Simpson CT	Gas	Gillette, WY	100	40.0	2000
Lange CT	Gas	Rapid City, SD	100	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, SD	100	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, SD	100	100.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, WY	100	95.0	2008
Colorado Electric:					
W.N. Clark #1-2	Coal	Canon City, CO	100	42.0	1955, 1959
Pueblo #6	Gas	Pueblo, CO	100	20.0	1949
Pueblo #5	Gas	Pueblo, CO	100	9.0	1941, 2001
AIP Diesel	Oil	Pueblo, CO	100	10.0	2001
Diesel #1-5	Oil	Pueblo, CO	100	10.0	1964
Diesel #1-5	Oil	Rocky Ford, CO	100	10.0	1964

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(1) During 2008, we began construction of Wygen III, a 110 MW mine-mouth coal-fired power plant. The plant is on schedule to be completed in mid-2010. We expect that Black Hills Power will operate the plant and own a 75% interest in the facility and MDU will own the remaining 25%. Our WRDC coal mine will furnish all of the coal fuel supply for the plant.

(2) Wyodak is a 362 MW mine-mouth coal-fired plant owned 80% by PacifiCorp and 20% (or 72.4 MW) by Black Hills Power. The baseload plant is operated by PacifiCorp and our WRDC coal mine furnishes all of the coal fuel supply for the plant.

The following table shows the Electric Utilities annual average cost of fuel utilized to generate electricity and the average price paid for purchased power per MWh during the last three years:

Fuel Source	2008[1] ($ per MWh)	2007[2] ($ per MWh)	2006[2] ($ per MWh)
Coal	$ 11.41	$ 8.94	$ 7.87
Gas and Oil	$ 87.57	$ 68.04	$ 75.77
Total Average Fuel Cost	$ 13.18	$ 11.84	$ 9.94
Purchased Power	$ 48.24	$ 40.79	$ 44.86

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(1) 2008 includes Colorado Electric from July 14, 2008 through December 31, 2008.

(2) Excludes Colorado Electric, which we did not acquire until July 14, 2008.

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Power Supply

The following table shows the power supply, by resource as a percent of the total power supply, for our Electric Utilities:

	2008	2007	2006
Coal-fired	44%	42%	40%
Gas and Oil	1	2	1
Total Generated	45%	44%	41%
Purchased	55	56	59
Total	100%	100%	100%

Purchased Power. Various agreements have been entered into to support our Electric Utilities capacity and energy needs beyond our regulated power plants generation. Key contracts include:

A power purchase agreement with PacifiCorp expiring in 2023, which provides for the purchase of 50 MW of coal-fired baseload power by Black Hills Power;

A reserve capacity integration agreement with PacifiCorp expiring in 2012, which makes 100 MW of reserve capacity in connection with the utilization of the Ben French CT units available to Black Hills Power;

A long-term contract with PSCo expiring in 2011, whereby Colorado Electric purchases a majority of its power. The contract provides for 280 MW of capacity and energy in 2009, increasing 10 MW per year to 300 MW in 2011;

Cheyenne Light s power purchase agreements with Black Hills Wyoming that provide Cheyenne Light with 40 MW of energy and capacity from our Gillette CT under a 10-year power purchase agreement expiring in August 2011, and 60 MW of unit contingent capacity and energy from our Wygen I facility under a 10-year agreement expiring the first quarter of 2013;

Cheyenne Light s 20-year purchase power agreement with Happy Jack Wind Power, LLC, expiring in September 2028, providing up to 29.4 MW of renewable energy from the Happy Jack Wind Farm to Cheyenne Light. Cheyenne Light has sold 67% of the output of this facility to Black Hills Power. Cheyenne Light and Black Hills Power receive 100% of the renewable energy credits under the agreement; and

Cheyenne Light and Black Hills Power s Generation Dispatch Agreement that requires Black Hills Power to purchase all of Cheyenne Light s excess energy.

Power Sales Agreements. Our Electric Utilities have various long-term power sales agreements. Key agreements include:

An agreement under which we supply up to 74 MW of capacity and energy to MDU for the Sheridan, Wyoming electric service territory through the end of 2016. The sales to MDU have been integrated into Black Hills Power s control area and are considered part of our firm native load. In accordance with the terms of the agreement, MDU has an option to participate in the ownership of the Wygen III plant that is currently being constructed. MDU has notified us of its intentions to exercise their option to participate in the Wygen III project and we expect to renegotiate the power sales agreement to reduce the energy and capacity supplied by us under the agreement;

An agreement with the City of Gillette, Wyoming, to provide the City its first 23 MW of capacity and energy annually. The sales to the City of Gillette have been integrated into Black Hills Power s control area and are considered part of our firm native load. The agreement renews automatically and requires a seven year notice of termination. As of December 31, 2008, neither party to the agreement had given a notice of termination; and

An agreement under which Black Hills Power supplies 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.

Transmission and Distribution. Through our electric utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 KV) and low voltage lines (69 or fewer KV). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2008, Electric Utilities owned or leased the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
Black Hills Power	SD, WY	497	2,834
Black Hills Power Jointly Owned	SD, WY	47	
Cheyenne Light	SD, WY	25	1,132
Colorado Electric	CO	195	3,179

Through Black Hills Power, we own 35% of a transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the MAPP region in the East. Black Hills Power s electric system is located in the WECC region, and 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 grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of the power price differentials between the two 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.

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 also 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.

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Operating Statistics

The following tables summarize regulated sales revenues, sales quantities and customers for our Electric Utilities segment. 2008 reported amounts include Colorado Electric from its July 14, 2008 acquisition date through December 31, 2008, whereas 2007 and 2006 amounts do not include Colorado Electric:

Sales Revenues	2008	2007	2006
	(in thousands)		
Residential:			
Black Hills Power	$ 46,854	$ 45,657	$ 40,491
Cheyenne Light	31,394	24,060	27,585
Colorado Electric	32,620		
Total Residential	110,868	69,717	68,076
Commercial:			
Black Hills Power	58,289	55,991	49,756
Cheyenne Light	51,609	38,871	44,785
Colorado Electric	28,531		
Total Commercial	138,429	94,862	94,541
Industrial:			
Black Hills Power	21,432	21,974	20,694
Cheyenne Light	9,716	7,306	8,540
Colorado Electric	16,280		
Total Industrial	47,428	29,280	29,234
Municipal:			
Black Hills Power	2,734	2,697	2,401
Cheyenne Light	973	797	832
Colorado Electric	2,289		
Total Municipal	5,996	3,494	3,233
Contract Wholesale:			
Black Hills Power	26,643	25,240	24,705
Off-system Wholesale:			
Black Hills Power	63,770	35,210	42,489
Cheyenne Light	6,105		
Colorado Electric	11,194		
Total Off-system Wholesale	81,069	35,210	42,489
Other:			
Black Hills Power	12,950	12,932	12,630
Cheyenne Light	394	208	421
Colorado Electric	1,346		
Total Other	14,690	13,140	13,051
Total Sales Revenues	$ 425,123	$ 270,943	$ 275,329

Quantities Generated and Purchased (MWh)	2008	2007	2006
Generated			
Coal-fired:			
Black Hills Power	1,731,838	1,758,280	1,729,636
Cheyenne Light	740,051 (1)		
Colorado Electric	138,424		
Total Coal	2,610,313	1,758,280	1,729,636
Gas and Oil-fired:			
Black Hills Power	61,801	90,618	54,299
Cheyenne Light			
Colorado Electric	306		
Total Gas and Oil	62,107	90,618	54,299
Total Generated:			
Black Hills Power	1,793,639	1,848,898	1,783,935
Cheyenne Light	740,051		
Colorado Electric	138,730		
Total Generated	2,672,420	1,848,898	1,783,935
Purchased:			
Black Hills Power	1,703,088	1,279,005	1,553,024
Cheyenne Light	590,622	1,047,782	978,613
Colorado Electric	1,028,029		
Total Purchased	3,321,739	2,326,787	2,531,637
Total Generated and Purchased	5,994,159	4,175,685	4,315,572

(1) Represents the Wygen II plant that began providing electricity to Cheyenne Light customers on January 1, 2008.

Quantity Sold (MWh)	2008	2007	2006
Residential:			
Black Hills Power	524,413	518,148	499,152
Cheyenne Light	255,345	251,313	249,888
Colorado Electric	284,294		
Total Residential	1,064,052	769,461	749,040
Commercial:			
Black Hills Power	699,734	690,702	667,220
Cheyenne Light	586,151	561,963	536,954
Colorado Electric	330,870		
Total Commercial	1,616,755	1,252,665	1,204,174
Industrial:			
Black Hills Power	414,421	434,627	433,019
Cheyenne Light	144,179	141,353	129,462
Colorado Electric	235,218		
Total Industrial	793,818	575,980	562,481
Municipal:			
Black Hills Power	34,368	34,661	32,961
Cheyenne Light	3,669	3,658	3,634
Colorado Electric	19,740		
Total Municipal	57,777	38,319	36,595
Contract Wholesale:			
Black Hills Power	665,795	652,931	647,444
Off-system Wholesale:			
Black Hills Power	1,074,398	678,581	942,045
Cheyenne Light	246,542		
Colorado Electric	230,333		
Total Off-system Wholesale	1,551,273	678,581	942,045
Total Quantity Sold	5,749,470	3,967,937	4,141,779
Losses and Company Use:			
Black Hills Power	83,598	118,253	115,118
Cheyenne Light	94,787	89,495	58,675
Colorado Electric	66,304		
Total Losses and Company Use	244,689	207,748	173,793
Total Energy	5,994,159	4,175,685	4,315,572

Degree Days	2008		2007		2006	
Heating Degree Days:	Actual	Variance from Normal	Actual	Variance from Normal	Actual	Variance from Normal
Actual						
Black Hills Power	7,676	6%	6,627	(7)%	6,472	(10)%
Cheyenne Light	7,435	1%	6,964	(6)%	6,789	(8)%
Colorado Electric	2,204	(5)%				
Cooling Degree Days:						
Actual						
Black Hills Power	482	(19)%	1,033	74%	931	56%
Cheyenne Light	372	36%	536	96%	486	78%
Colorado Electric	500	(12)%				

Electric Customers at Year-End	2008	2007	2006
Residential:			
Black Hills Power	53,765	53,057	52,521
Cheyenne Light	35,205	35,175	34,982
Colorado Electric	81,561		
Total Residential	170,531	88,232	87,503
Commercial:			
Black Hills Power	12,213	12,073	11,917
Cheyenne Light	4,563	4,381	4,136
Colorado Electric	11,155		
Total Commercial	27,931	16,454	16,053
Industrial:			
Black Hills Power	40	41	46
Cheyenne Light	2	2	2
Colorado Electric	93		
Total Industrial	135	43	48
Contract Wholesale:			
Black Hills Power	3	3	3
Other:			
Black Hills Power	3,010	3,012	2,996
Cheyenne Light	6	6	6
Colorado Electric	480		
Total Other	3,496	3,018	3,002
Total Customers at Year-End	202,096	107,750	106,609

Cheyenne Light Natural Gas Distribution

Cheyenne Light s natural gas distribution system serves approximately 33,300 natural gas customers in Cheyenne and other portions of Laramie County, Wyoming. Our peak capacity was approximately 40 thousand Dth during the year ending December 31, 2008. The following table summarizes certain operating information of these natural gas distribution operations:

	2008	2007	2006
Sales Revenues (in thousands):			
Residential	$ 28,059	$ 18,985	$ 27,854
Commercial	13,751	9,437	14,640
Industrial	5,668	3,340	6,605
Other	818	706	927
Total Sales Revenues	$ 48,296	$ 32,468	$ 50,026
Sales Margins (in thousands):			
Residential	$ 10,083	$ 6,408	$ 6,389
Commercial	3,177	2,268	2,258
Industrial	483	436	495
Other	818	707	927
Total Sales Margins	$ 14,561	$ 9,819	$ 10,069
Volumes Sold (Dth):			
Residential	2,582,248	2,380,945	2,325,229
Commercial	1,501,025	1,382,150	1,351,412
Industrial	689,945	664,807	711,126
Total Volumes Sold	4,773,218	4,427,902	4,387,767

Gas Utilities Segment

At December 31, 2008, Gas Utilities owned the gas transmission and distribution lines shown below:

State	Intrastate Gas Transmission Pipelines (in line miles)	Gas Distribution Mains and Service Lines (in line miles)
Colorado	122	857
Nebraska	51	3,438
Iowa	170	2,304
Kansas	286	1,279

The following tables summarize regulated Gas Utilities sales revenues, sales margins and volumes for the period of July 14, 2008 to December 31, 2008 and customers as of December 31, 2008:

	Sales Revenues (in thousands)	Sales Margins (in thousands)	Volumes Sold (Dth)
Residential:			
Colorado	$ 27,928	$ 5,984	2,344,549
Nebraska	60,624	19,460	5,115,805
Iowa	47,338	16,335	4,126,150
Kansas	31,456	12,436	2,682,850
Total Residential	167,346	54,215	14,269,354
Commercial:			
Colorado	6,356	1,131	563,169
Nebraska	20,705	4,952	2,133,433
Iowa	26,003	5,210	2,749,234
Kansas	10,092	2,693	1,063,356
Total Commercial	63,156	13,986	6,509,192
Industrial:			
Colorado	1,495	232	164,112
Nebraska	1,640	173	248,256
Iowa	1,581	105	196,841
Kansas	14,667	1,041	1,586,306
Total Industrial	19,383	1,551	2,195,515
Transportation:			
Colorado	278	278	347,822
Nebraska	4,703	4,703	12,930,165
Iowa	1,609	1,609	6,312,050
Kansas	2,409	2,409	7,215,038
Total Transportation	8,999	8,999	26,805,075
Other:			
Colorado	39	39	
Nebraska	907	907	320
Iowa	457	457	18,301
Kansas	1,600	1,177	60,917
Total Other	3,003	2,580	79,538
Total Regulated	261,887	81,331	49,858,674
Non-regulated Services	15,189	3,895	
Total	$ 277,076	$ 85,226	49,858,674

Degree Days	2008	
Heating Degree Days:	Actual	Variance From Normal
Colorado	2,376	(7)%
Nebraska	2,458	
Iowa	2,909	3%
Kansas	1,897	(3)%

Gas Customers at Year-End	December 31, 2008
Residential:	
Colorado	64,601
Nebraska	177,432
Iowa	133,442
Kansas	96,593
Total Residential	472,068
Commercial:	
Colorado	3,579
Nebraska	15,034
Iowa	15,467
Kansas	9,463
Total Commercial	43,543
Industrial:	
Colorado	208
Nebraska	149
Iowa	84
Kansas	1,267
Total Industrial	1,708
Transportation:	
Colorado	21
Nebraska	4,758
Iowa	397
Kansas	1,174
Total Transportation	6,350
Other:	
Colorado	
Nebraska	2
Iowa	69
Kansas	8
Total Other	79
Total Customers at Year-End	523,748

Business Characteristics

Seasonal Variations of Business

Our Electric Utilities and Gas Utilities 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 Utilities have 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.

Competition

We generally have limited competition for the retail distribution of electricity and natural gas in our service areas. In the past, various restructuring and competitive initiatives have been discussed in the states in which our utilities operate, but none have been implemented. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge. In Colorado, our electric utility is subject to rules which require competitive bidding for generation supply. Accordingly, we face competition from other utilities and IPP companies for the right to provide generation for Colorado Electric.

Regulation and Rates

State Regulation

Our utilities are subject to the jurisdiction of the public utilities commissions in the states in which they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their state to secure bonds or other securities.

We distribute natural gas in five states. All of our Gas Utilities have cost adjustments that allow them to pass the prudently-incurred cost of gas through to the customer. In Kansas and Nebraska, we are also allowed to recover a portion of uncollectible accounts through the cost adjustments. In Kansas we have also established a weather normalization tariff that provides a pass-through mechanism for weather margin variability from the level used to establish base rates to be paid by the customer.

We produce and distribute power in four states. The regulatory provisions for recovering power costs vary by state. In South Dakota, Wyoming, Montana and Colorado, we have cost adjustment mechanisms for our Electric Utilities that serve a purpose similar to the cost adjustment mechanisms in our Gas Utilities. At Cheyenne Light, our pass-through mechanism relating to transmission, fuel and purchased power costs is subject to a $1.0 million threshold: we collect or refund 95% of the increase or decrease that exceeds the $1.0 million threshold, and we absorb the increase or retain the savings for changes below the threshold.

In South Dakota, we have three adjustment mechanisms: transmission, steam plant fuel and conditional energy cost adjustment. The transmission and steam plant fuel adjustment clauses will either pass along or give credits back to South Dakota customers based on actual costs incurred on a yearly basis. The conditional energy cost adjustment relates to purchased power and natural gas used to generate electricity. These costs are subject to $2.0 million and $1.0 million cost bands where Black Hills Power absorbs the first $2.0 million of increased costs or retains the first $1.0 million in savings. Beyond these thresholds, costs or refunds begin to be passed on to South Dakota customers through annual calendar-year filings.

In Colorado, we have a cost adjustment for increases or decreases to purchased power and fuel costs and a transmission cost adjustment. The cost adjustment clause provides for the direct recovery of increased purchased power and fuel costs or the issuance of credits for decreases in purchased power and fuel costs. The transmission cost adjustment is a rider to the customer s bill which allows the utility to earn a return on new transmission investment and recover operations and maintenance costs related to transmission.

The above mechanisms allow the utilities to collect, or refund, the difference between the costs of commodities imbedded in our base rates and the actual costs of the commodities without filing a general rate case. In some instances, such as the transmission cost adjustment in Colorado, the utility has the opportunity to earn its authorized return on new capital investment.

Certain states in which we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2008, we were subject to the following renewable energy portfolio standards or objectives:

South Dakota. South Dakota has adopted a renewable portfolio objective that encourages utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015. Absent a specific renewable energy mandate in South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers.

Montana. In 2005, Montana established a renewable portfolio standard that requires Black Hills Power to obtain a percentage of its retail electric sales in Montana from eligible renewable resources according to the following schedule: (i) 5% for compliance years 2008-2009; (ii) 10% for compliance years 2010-2014; and (iii) 15% for compliance year 2015 and thereafter. Utilities can meet this standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits, by purchasing the renewable-energy credits separately, or by a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from ratepayers for contracts pre-approved by the MTPSC.

Colorado. In 2007, the Colorado legislature adopted a renewable energy standard that requires our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) at least 10% of its retail sales by 2010; (ii) 15% of retail sales by 2015; and (iii) 20% of retail sales by 2020. Of these amounts, 4% must be generated from solar renewable resources with one-half of the solar resources being located at customer facilities. The new law limits the net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) to 2% and encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism.

Wyoming is also exploring the implementation of renewable energy portfolio standards. Mandatory portfolio standards have increased, and may continue to increase the power supply costs of our electric operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery.

In connection with the Aquila Transaction, the CPUC, NPSC, IUB and KCC approved orders or settlement agreements providing that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and (ii) neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans.

The public utility commissions determine the rates our utilities are allowed to charge for their services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of our costs, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment.

The following summarizes our recent rate case activity:

	Type of Service	Date Requested	Date Effective	Amount Requested	Amount Approved
				(in millions)	
Kansas Gas[1]	Gas	11/2006	6/2007	$ 7.2	$ 5.1
Nebraska Gas[2]	Gas	11/2006	9/2007	$ 16.3	$ 9.2
Cheyenne Light[3]	Electric	3/2007	1/2008	$ 8.4	$ 6.7
Cheyenne Light[4]	Gas	3/2007	1/2008	$ 4.6	$ 4.4
Iowa Gas[5]	Gas	6/2008	Pending	$ 13.6	Pending
Colorado Gas[6]	Gas	6/2008	Pending	$ 2.8	Pending

(1) In April 2007, Kansas Gas entered into an agreement that resulted in a black box settlement of $5.1 million, with a residential customer charge of $16 per month that will recover approximately 65% of the margin through the customer charge. The KCC approved the settlement in May 2007, and the new rates were implemented on June 1, 2007.

(2) In November 2006, Nebraska Gas filed for a $16.3 million rate increase. Interim rates were implemented in February 2007 and, in July 2007, the NPSC granted a $9.2 million increase in annual revenues based on an equity return of 10.4% on a capital structure of 51% equity and 49% debt. Nebraska Gas appealed the decision, and the district court affirmed the NPSC order in February 2008. Because Nebraska Gas collected interim rates subject to refund, it was required to refund to customers the difference between the higher interim rates and the final rates plus interest (approximately $5.6 million).

(3) In November 2007, the WPSC granted Cheyenne Light a $6.7 million increase in annual electric utility revenues based on an equity return of 10.9% on a capital structure of 54% equity and 46% debt. The new rates were implemented on January 1, 2008. The WPSC also placed the Wygen II power plant into rate base and approved a pass-through mechanism for Cheyenne Light s electric business. Under the pass-through mechanism, the annual increase or decrease for transmission, fuel and purchased power costs is passed through to customers, subject to a $1.0 million threshold. Under its tariff, Cheyenne Light collects or refunds 95% of the increase or decrease that exceeds the $1.0 million threshold; for changes below the threshold, Cheyenne Light absorbs the increase or retains the savings.

(4) In November 2007, the WPSC granted Cheyenne Light a $4.4 million increase in annual gas utility revenues based on an equity return of 10.9% on a capital structure of 54% equity and 46% debt. The new rates were implemented on January 1, 2008.

(5) In June 2008, Iowa Gas filed for a $13.6 million rate increase. The proposed increase is based on an equity return of 11.5% on a capital structure of 52% equity and 48% debt. Interim rates with increases totaling $9.5 million annually were implemented on June 13, 2008. On August 12, 2008, the IUB issued an order that extended the usual ten month time limit for consideration of the general rate increase by three months, from April 2, 2009 to July 2, 2009. The IUB has until July 2, 2009 to issue a decision on our rate request. If interim rates exceed final approved rates, the difference plus interest will be refunded or credited to customers.

(6) In June 2008, Colorado Gas filed for a $2.8 million rate increase. On February 4, 2009, a settlement of the rate case (of which all parties either supported or did not oppose) was presented to an administrative law judge. The settlement provides for an increase of $1.4 million, a return on equity of 10.25% and a capital structure of 50.48% equity and 49.52% debt. The administrative law judge will make a recommendation regarding the settlement to the CPUC and it will make the final decision on the settlement. The CPUC has until June 16, 2009 to issue a decision on our rate request, but as part of the settlement, the parties requested an expeditious approval to allow for an earlier effective date.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

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 maintain tariffs and rate schedules on file with FERC that govern the rates, terms, and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. 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. In that regard, our public utility subsidiaries provide FERC-jurisdictional services subject to FERC s oversight.

Our Electric Utilities and our non-regulated subsidiary, Black Hills Wyoming, are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Black Hills Power owns and operates FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC s regulations.

On September 29, 2008, Black Hills Power requested FERC approval to revise the method used to determine the revenue component of the utility s open access transmission tariff, and increase the utility s annual transmission revenue requirement by approximately $4.5 million. The proposed revenue requirement is based on an equity return of 10.95%. On December 12, 2008, Black Hills Power filed a settlement agreement with FERC. The settlement agreement was reached with the only two interveners in the rate case. The settlement sought annual transmission revenue of $3.8 million based on an equity return of 10.80%, 57% equity and 43% debt. The capital structure will remain fixed as annual filings are made based on actual capital dollars and expenses. The revised method used to determine the annual transmission revenue requirement is referred to as a formulaic rate. Using the formulaic rate, we forecast capital additions for the upcoming year and are allowed to earn a return on assets as they are placed in service. The rate also includes a true-up of the previous year s capital forecast and allows an adjustment to collect the actual operations and maintenance expenses for the previous year. FERC approved the settlement agreements in February 2009 with a January 1, 2009 effective date.

The Federal Power Act gave FERC authority to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners, and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards, and NERC, in conjunction with regional reliability organizations that operate under FERC s and NERC s authority and oversight, enforce those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of holding company systems. As a holding company with a centralized service company subsidiary, Black Hills Service Company, we are subject to FERC s authority under PUHCA 2005.

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Environmental Matters

We are subject to numerous federal, state and local laws and regulations relating to the protection of the environment and the safety and health of personnel and the public. These laws and regulations affect a broad range of our utility activities, and generally require (i) the protection of air and water quality; (ii) the identification, generation, storage, handling, transportation, disposal, record-keeping, labeling, reporting of, and emergency response in connection with hazardous and toxic materials and wastes, including asbestos; (iii) the protection of plant and animal species and minimization of noise emissions; and, (iv) safety and health standards, practices and procedures that apply to the workplace and to the operation of our facilities.

Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants. The ultimate cost could be significantly different from the amounts estimated. The following table does not reflect any costs for complying with future laws or regulations and also does not reflect costs relating to additional power generation facilities at our Colorado Electric utility that are pending regulatory approvals that cannot be reasonably estimated at this time.

Environmental Expenditures	Total (in millions)
2009	$ 17.4
2010	5.9
2011	12.9
Total	$ 36.2

Water Issues

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 that are required to have NPDES permits have those permits in place and are in compliance with discharge limitations. We are not aware of any proposed regulations that will have a significant impact on our operations. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities under this program have their required plans in place.

Air Emissions

Our generation facilities are subject to federal, state and local laws and regulations relating to the protection of air quality. These laws and regulations cover, among other pollutants, carbon monoxide, SO_2, NOx, mercury and particulate matter. In addition, CO_2 is included as a potential emission that may be subject to regulation in the future. Power generating facilities burning fossil fuels emit each of the foregoing pollutants and, therefore, are subject to substantial regulation and enforcement oversight by various governmental agencies.

Clean Air Act

Title IV of the Clean Air Act created an SO_2 allowance trading program as part of the federal acid rain program. Each allowance gives the owner the right to emit one ton of SO_2, and certain facilities are allocated allowances based on their historical operating data. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances may be traded so affected units that expect to emit more SO_2 than their allocated allowances may purchase allowances in the open market.

Title IV applies to several of our generation facilities, including the Neil Simpson II, Neil Simpson CT, Lange CT, Wygen II and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2038. For future plants, we plan to secure the requisite 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, 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 new projects.

Title V of the Clean Air Act requires that all our generating stations obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen II. As a new plant, this facility is allowed to operate under its construction permit until the Title V permit is issued by the state. The Title V application was submitted in 2008, with the permit expected in 2009.

Multi-pollutant regulations

Approximately 38% of our electric generating capacity is coal-fired. In 2005, the EPA issued CAMR regulations with respect to SO_2, NOx, and mercury emissions from certain power plants that burn fossil fuels. These new rules implement emission limits, monitoring and cap and trade requirements beginning as early as 2009.

In February 2008, the United States Court of Appeals for the D.C. Circuit overturned the CAMR regulations; however, under this ruling, the EPA must either properly remove mercury from regulation under the hazardous air pollutant provisions of the Clean Air Act or develop standards requiring maximum achievable control technology for mercury emissions. Moreover, although this ruling impacts federal CAMR requirements, it does not necessarily impact state mercury legislation and 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 state air permit for Wygen II provides mercury emission limits and monitoring requirements with which we are in compliance. Wygen II has been utilized for study and review of mercury emission control technology and has mercury monitors in place. We will also be adding mercury monitors to Neil Simpson II.

In July 2008, a three-judge panel of the United States Court of Appeals for the D.C. Circuit vacated CAIR and remanded the rule to the EPA for revision consistent with the court s decision. The EPA subsequently requested a rehearing, and in December 2008, the court partially reversed its July 2008 ruling. Under the December 2008 ruling, the program s pollution control requirements remain in place while the EPA rewrites the CAIR rules in accordance with the July 2008 decision.

Federal multi-pollutant legislation is also being considered that would require reductions similar to the EPA rules and may add requirements for the reduction of greenhouse gas emissions.

Global Climate Change

We utilize a diversified energy portfolio that includes a fuel mix of coal, natural gas and wind sources. Of these fuel mixes, coal-fired power plants are the most significant sources of CO_2 emissions. We believe it is possible that greenhouse gases may be regulated in the near future. Although we cannot predict specifically how greenhouse gases will be regulated, any federally mandated greenhouse gas reductions or limits on CO_2 emissions could have a material impact on our financial position or results of operations. In addition to legislative activity, climate proposals have been proposed in various states and climate change issues are the subject of a number of lawsuits the outcome of which could impact the utility industry. For example, in November 2007, the Governor of Colorado published a Colorado Climate Action Plan that calls for reduction in greenhouse gas emissions of 20% by 2020, with additional reductions by 2050. We will continue to review greenhouse gas impacts as legislation or regulation develops and litigation is resolved.

In connection with climate change initiatives, many states have enacted, and others are considering, renewable energy portfolio standards that require electric utilities to meet certain thresholds for the production or use of renewable energy. Colorado Electric is subject to renewable energy portfolio standards in Colorado. Black Hills Power is subject to mandatory renewable energy portfolio standards in Montana and voluntary standards in South Dakota. In the near future, we expect similar (if not more challenging) renewable energy portfolio standards to be developed in other jurisdictions in which we operate. Federal legislation for renewable energy portfolio standards is also under consideration. We anticipate significant additional costs to comply with any federally or state mandated renewable energy standards, which we would expect to pass on to our customers. However, we cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been proposed at the federal or state level.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Under appropriate state permits, we dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Ash and wastes from flue gas and sulfur removal from the Wyodak, Neil Simpson I, Ben French, Neil Simpson II and Wygen 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 change would increase disposal 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. The Osage power plant has an on-site ash impoundment that is near capacity and will be gradually transferring disposal to the Wyodak coal mine. The W.N. Clark plant sends coal ash to a permitted, privately-owned landfill. 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 are in place that require PacifiCorp to be responsible for any such costs related to the solid waste from its 80% ownership 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 a hazardous material that requires special treatment, including previously disposed solid waste. In that event, the regulatory authority could hold entities that disposed of such waste responsible for remedial treatment.

Past Operations

Some federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment.

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing (MGP) sites. From our review of data provided by Aquila and subsequent discussions with contractors, we estimate that investigative and remedial action costs will be in the range of $1.4 million to $3.7 million. The acquisition also provided for a $1.0 million insurance recovery, which will be used to help offset the remediation costs of these sites. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or financial viability of other responsible parties.

We have received rate orders that enable us to recover environmental cleanup costs in certain jurisdictions. In other jurisdictions, there is regulatory precedent for recovery of these costs. We are also pursuing recovery or agreements as to responsibility from other potentially responsible parties when and where permitted.

Non-regulated Energy Group

Our Non-regulated Energy Group, which operates through various 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;
- Power Generation;
- Coal Mining; and
- Energy Marketing.

Oil and Gas Segment

Our Oil and Gas segment, which conducts business through BHEP and its subsidiaries, acquires, explores for, develops and produces natural gas and crude oil for sale into commodity markets. As of December 31, 2008, the principal assets of our Oil and Gas segment included (i) operating interests in oil and natural gas properties, including 562 gross and 525 net wells in the San Juan Basin of New Mexico and Colorado (including significant holdings within the tribal lands of the Jicarilla Apache and Southern Ute Nations), the Powder River and Big Horn Basins of Wyoming, the Piceance Basin of Colorado, and the Nebraska section of the Denver Julesberg Basin; (ii) non-operated interests in oil and natural gas properties including 534 gross and 76 net wells located in California, Colorado, Louisiana, Montana, North Dakota, Oklahoma, Texas and Wyoming; and (iii) a 44.7% ownership interest in the Newcastle gas processing plant and associated gathering system located in Weston County, Wyoming. The plant, which is operated by Western Gas Partners, LP, is adjacent to our producing properties in that area, and BHEP s production accounts for the majority of the facility s throughput. We also own natural gas gathering, compression and treating facilities serving the operated San Juan and Piceance Basin properties and working interests in similar facilities serving our non-operated Montana and Wyoming properties.

At December 31, 2008, we had total reserves of approximately 186 Bcfe, of which natural gas comprised 83% and oil comprised 17% of total reserves. The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region. Approximately 31% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County, 20% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties and 30% 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% discounted present value of estimated future net revenues as of December 31, 2008 and 2007. The 2008 and 2007 information presented is based on reports prepared by Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm located in Fort Worth, Texas. 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. Additional information on our oil and gas reserves and related financial data can be found in Note 22 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Proved Developed Reserves:	December 31, 2008			December 31, 2007		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)*
Wyoming	4,167	14,486	39,488	4,954	15,164	44,888
New Mexico	13	43,799	43,877	3	45,646	45,664
Colorado	1	22,563	22,569		23,497	23,497
Montana	26	2,231	2,387	35	3,034	3,244
Oklahoma	5	4,080	4,110	9	3,411	3,465
North Dakota	216	298	1,594	90	133	673
Other states	1	1,244	1,250	4	1,637	1,661
Total Proved Developed Reserves	4,429	88,701	115,275	5,095	92,522	123,092

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

Proved Undeveloped Reserves:	December 31, 2008			December 31, 2007		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	444	5,327	7,991	555	1,655	4,985
New Mexico		13,352	13,352		24,293	24,293
Colorado		39,466	39,466		49,221	49,221
Montana		4,474	4,474		2,453	2,453
Oklahoma	9	2,604	2,658	9	2,573	2,627
North Dakota	303	508	2,326	148	247	1,135
Total Proved Undeveloped Reserves	756	65,731	70,267	712	80,442	84,714

Total Proved Reserves:	December 31, 2008			December 31, 2007		
	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)	Oil (Mbbl)	Natural Gas (MMcf)	Total (MMcfe)
Wyoming	4,611	19,813	47,479	5,509	16,819	49,873
New Mexico	13	57,151	57,229	3	69,939	69,957
Colorado	1	62,029	62,035		72,718	72,718
Montana	26	6,705	6,861	35	5,487	5,697
Oklahoma	14	6,684	6,768	18	5,984	6,092
North Dakota	519	806	3,920	238	380	1,808

Other states	1	1,244	1,250	4	1,637	1,661
Total Proved Reserves	5,185	154,432	185,542	5,807	172,964	207,806

	December 31, 2008	December 31, 2007
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	62%	59%
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	38%	41%
Present value of estimated future net revenues, before tax (in thousands)	$ 195,960	$ 424,849

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

	December 31, 2008	December 31, 2007
Gas per Mcf	$ 4.44	$ 5.88
Oil per Bbl	$ 32.74	$ 83.23

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2008, we participated in drilling 82 gross (31.38 net) development and exploratory wells, with a net well success rate of approximately 89%. 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 our ownership interest, while net wells represent our fractional ownership interests within those wells.

Year ended December 31,	2008		2007		2006	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	3.88		3.67		28.20	
New Mexico	6.70	1.00	17.30		21.00	1.00
Montana	5.82		8.98	0.45	3.42	0.02
North Dakota	0.31	0.14		2.00		
Other states	7.84	2.18	2.35		0.20	1.00
Total	24.55	3.32	32.30	2.45	52.82	2.02

Year ended December 31,	2008		2007		2006	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Wyoming	0.75		0.61		0.04	
New Mexico	2.00		1.60		1.00	
Montana			0.27	0.25	2.35	0.50
North Dakota	0.76		0.37			
Other states					1.28	
Total	3.51		2.85	0.25	4.67	0.50

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As of December 31, 2008, we were participating in the drilling of 12 gross (4.28 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the year ended December 31, 2008 were not material to the overall operations of this segment.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2008:

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Wyoming	395	146	541	310.45	6.61	317.06
New Mexico	2	152	154	1.91	148.30	150.21
Colorado	1	80	81		58.81	58.81
Montana	3	187	190	0.49	41.23	41.72
North Dakota	12		12	1.78		1.78
Oklahoma		67	67		10.54	10.54
Other states	1	50	51	0.01	21.71	21.72
Total	414	682	1,096	314.64	287.20	601.84

Acreage

The following table summarizes our undeveloped, developed and total acreage by state as of December 31, 2008 (in thousands):

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Wyoming	50,869	37,407	25,070	15,846	75,939	53,253
New Mexico	39,268	39,091	25,274	22,773	64,542	61,864
Colorado	46,276	33,769	38,512	32,496	84,788	66,265
Montana	719,287	128,943	102,472	18,877	821,759	147,820
Oklahoma	19,297	3,586	21,204	3,296	40,501	6,882
North Dakota	29,090	3,958	5,799	940	34,889	4,898
Other states	38,002	27,769	60,656	47,415	98,658	75,184
Total	942,089	274,523	278,987	141,643	1,221,076	416,166

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 inhibit 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. Crude oil and natural gas development and production activities are subject to various laws and regulations governing a wide variety of matters. 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. We are also subject to various mineral conservation laws and regulations, including the regulation of the size of drilling and spacing/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.

Various federal agencies within the United States Department of the Interior, particularly the Bureau of Land Management, the Minerals Management Service and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas 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 our cost of doing business on tribal lands and impact the viability of our gas, oil and gathering operations on such lands.

In addition to being subject to federal and tribal regulations, we must also comply with state and county regulations, which have been going through significant change over the past two years. In 2008, new state regulations were implemented in New Mexico which increased the regulatory requirements associated with drilling pits. Also in 2008, new county regulations were proposed which could potentially add additional county approvals to the permitting process. In 2007, Colorado legislation changed the structure of the oil and gas commission, which has developed and approved significant changes to oil and gas regulations for implementation in 2009. Changes such as these have increased, and will continue to increase, costs and add uncertainty with respect to the timing and receipt of permits.

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

Under state, federal and tribal 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 clean up 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.

Global Climate Change. The Oil and Gas segment is impacted by regulation in the state of New Mexico where legislation was passed requiring the tracking and reporting of greenhouse gas emissions, beginning with calendar year 2008. We anticipate other states may implement such programs in the future.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates unregulated power plants. We held varying interests in independent power plants operating in Wyoming and Idaho with a total net ownership of 141 MW as of December 31, 2008. We also hold investment interests in power-related funds with a net ownership interest of 3.0 MW.

During 2008, we sold seven IPP plants with 974 MW of capacity to affiliates of Hastings and IIF for a purchase price of $840 million, subject to customary adjustments. We completed the sale in July 2008 and received net cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and net of the required payoff of $67.5 million of project debt. Results of the IPP Transaction are reported as discontinued operations. See Notes 1 and 16 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Portfolio Management

We sell capacity and energy under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell approximately 99% 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 economical.

As of December 31, 2008, the power plant ownership interests held by our Power Generation segment included:

IPP	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	Start Date
Gillette CT	Gas	Gillette, Wyoming	100%	40.0	2001
Wygen I[(1)]	Coal	Gillette, Wyoming	100%	90.0	2003
Glenns Ferry Cogeneration	Gas	Glenns Ferry, Idaho	50%	5.5	1996
Rupert Cogeneration	Gas	Rupert, Idaho	50%	5.5	1996
Ontario Cogeneration[(2)]	Gas	Ontario, California	100%		1984

(1) In January 2009, a 23.5% ownership interest in this plant was sold to MEAN.
(2) The Ontario Cogeneration plant was decommissioned during 2008.

Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette energy complex. The facility s energy and capacity is sold to Cheyenne Light under a 10-year power purchase agreement that expires in August 2011.

Wygen I. The Wygen I facility is a mine-mouth, coal-fired plant with a total nameplate capacity of 90 MW located at our Gillette energy complex. We sell 60 MW of unit contingent capacity and energy from this plant to Cheyenne Light under a 10-year agreement that expires in the first quarter of 2013.

In August 2008, we entered into a definitive agreement to sell a 23.5% undivided ownership interest in Wygen I to MEAN and completed the sale in January 2009. In connection with this sale transaction, we entered into agreements with MEAN under which it will make payments for costs associated with administrative services, plant operations and coal supply provided by our Coal Mining subsidiary during the life of the facility. We also terminated a 10-year power purchase agreement under which MEAN was obligated to purchase 20 MW of power annually from Wygen I. We retain responsibility for plant operations following the transaction.

Idaho Cogeneration Facilities. Through partnership investments, we own a 50% 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 the Idaho Power Company under 20-year Firm Energy Agreements, which expire in 2016. Steam production is sold to Idaho Fresh-Pak, Inc. under agreements that expire in late 2016. The Rupert facility operated normally through 2008 with no adverse conditions. The steam host at Glenns Ferry suspended operations in late 2007, and the plant did not operate in 2008. The facility maintained revenues through the sale of the contracted gas supplies. The steam host suspension prevented the facility from meeting its QF commitment for 2008. An application for a waiver of QF qualifying standards was submitted to FERC in late 2008. Absent FERC approval of the waiver or a contract with a new steam host, the continued suspension of the current steam host could have an adverse effect on the facility s operation, including its ability to meet QF requirements and the performance requirements under the related energy sales agreement in 2009. The Idaho partnerships have reserved their contractual rights with the steam host, as the steam host is jointly and severally liable under the Firm Energy Agreements with Idaho Power.

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.

With respect to the merchant power sector, the FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity, and foster competition within the wholesale electricity markets. In addition, although the deregulation efforts that caused some vertically integrated utilities to separate their generation, transmission, and distribution businesses have slowed considerably since the merchant energy crisis in 2001. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. However, regulatory pressures for utilities to competitively bid generation resources may provide upside opportunity for independent power in some regions.

Regulation. Many of the environmental laws and regulations applicable to our Electric Utilities also apply to our Power Generation operations. See the discussion under the Environmental and Regulation captions for the Utilities Group for additional information on certain laws and regulations described below.

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 the EPA 2005, FERC s regulations under PURPA required that electric utilities (i) purchase power generated by QFs at a price based on the purchasing utility s full avoided cost of producing power, (ii) sell back-up, interruptible, maintenance and supplemental power to the QF on a non-discriminatory basis, and (iii) interconnect with any QF in its service territory, and, if required, transmit power if they do not purchase it. Our Glenns Ferry and Rupert facilities are QFs. The enactment of the EPA 2005 did not affect the existing contracts for these facilities because they operate under contracts governed by laws in effect prior to EPA 2005. In order to secure the benefits of contracts entered pursuant to PURPA, our QFs must comply with certain operating requirements established by FERC, or secure a waiver of these requirements. If we fail to do so, we could incur contractual liability to the electric utility that purchases power generated by the QF.

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. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs, including Wygen I and Gillette CT. 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.

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Clean Air Act. The Clean Air Act impacts our Power Generation business in a manner similar to the impact disclosed for our Electric Utilities. Our Gillette CT and Wygen I facilities are subject to Titles IV and V of the Clean Air Act and have the required permits in place. As a result of SO_2 allowances credited to us from the installation of sulfur removal equipment at our jointly owned Wyodak plant, we hold sufficient allowances for our Gillette CT and Wygen plants through 2038, without purchasing additional allowances.

Clean Water Act. The Clean Water Act impacts our Power Generation business in a manner similar to the impact described above for our Electric Utilities. Each of our facilities required to have NPDES permits have those permits and are in compliance with discharge limitations. Also, as the EPA regulates surface water oil pollution prevention through its oil pollution prevention regulations, each of our facilities regulated under this program have the requisite plans in place.

Solid Waste Disposal. We dispose of all Wygen I coal ash and scrubber wastes in mined areas at our WRDC coal mine under the terms and conditions of a state permit. The factors discussed under this caption for the Utilities Group also impact our Power Generation segment in a similar manner.

Global Climate Change. The factors discussed under this caption for the Utilities Group also apply to our Power Generation segment.

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, which contains one of the largest coal reserves in the United States. We produced approximately 6 million tons of coal in 2008. 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% and 9.0%, respectively, of the selling price on all federal and state coal. As of December 31, 2008, we had coal reserves of approximately 274 million tons, based on internal engineering studies. The reserve life is equal to approximately 42 years at expected production levels.

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

- Our electric utilities, Black Hills Power and Cheyenne Light;
- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by Black Hills Power;
- PacifiCorp for the Dave Johnston power plant located near Casper, Wyoming and served by rail;
- Our non-regulated mine-mouth power plant, Wygen I; and
- Certain regional industrial customers served by truck.

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% (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 into service January 1, 2008.

The price for unprocessed coal sold to PacifiCorp for its 80% interest in the Wyodak plant is determined by a coal supply agreement which was executed in 2001 and terminates in 2022. The price for coal sold to PacifiCorp for its Dave Johnston plant is determined by a coal supply agreement which was executed in 2007 and terminates in 2011.

We expect to increase our coal production to supply for additional mine-mouth generating capacity related to the 110 MW Wygen III plant, which is currently being constructed and is expected to utilize approximately 0.6 million tons of coal per year when the plant begins commercial operations in 2010.

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 to 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 applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation, and restoration of our 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 have accrued approximately $17.7 million for reclamation costs as of December 31, 2008. If additional requirements or changes to current requirements are imposed in the future, we may experience a material increase in reclamation costs.

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, 2008 were approximately 1.9 million MMBtu of gas and approximately 7,900 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.

We operate our marketing business through the following strategies:

- Producer Services
  - Natural gas
  - Crude oil
- Wholesale Trading
  - Transportation
  - Storage
  - Proprietary

Our total gross margin recognized for each of the following years was derived from our marketing strategies according to the following approximate percentages (rounded to the nearest 5%):

	2008	2007	2006
Wholesale trading (storage)	15%	30%	25%
Wholesale trading (transportation)	30%	30%	25%
Producer services (natural gas)	10%	5%	5%
Producer services (crude oil)	15%	10%	5%
Subtotal	70%	75%	60%
Wholesale trading (proprietary and other)	30%	25%	40%
Total gross margin	100%	100%	100%

We have various long-term natural gas transportation and storage positions in our marketing portfolio that enhance our potential for long-term earnings growth by providing strong upside potential and definable downside risk. A substantial portion of these contractual positions include a right-of-first-refusal provision that provides us the opportunity to extend or renew favorable positions as their terms expire.

The total volumes of transportation capacity rights we held at December 31, 2008 were as follows:

	Term Until Expiration			
Region	Less than 2 Years (2009 and 2010) (Bcf of natural gas)	2 to 4 Years (2011 2013)	Greater than 4 Years (2014 and beyond)	Total Volume
Rockies	46.5	32.2	46.7	125.4
West	47.9	10.5	18.6	77.0
MidContinent	69.0	1.8		70.8
Total Capacity	163.4	44.5	65.3	273.2

The firm storage capacity rights we held at December 31, 2008 included:

Region	Volume (Bcf)	Term
MidContinent/Upper Midwest	1.0	01/09 03/09
MidContinent/Upper Midwest	1.0	01/09 06/10
MidContinent/Upper Midwest	1.0	01/09 03/12
MidContinent/Upper Midwest	1.0	01/09 03/13
MidContinent/Upper Midwest	1.0	01/09 03/17
West/Northwest	0.3	01/09 03/09
West/Northwest	0.5	04/09 03/10

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.

Regulation. Various aspects of our marketing activities are regulated by the FERC. During 2007, following an internal review of natural gas marketing activities conducted within the Energy Marketing segment, we identified possible instances of noncompliance with regulatory requirements applicable to those activities. We notified the staff of FERC of our findings. We have also evaluated public announcements of civil penalties that have been levied against other companies for violations of similar FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on us. 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 our consolidated net income of any particular period, but is not expected to have a material impact upon our overall consolidated financial position.

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 a second office building consisting of approximately 19,900 square feet and a warehouse building and shop with approximately 25,200 square feet. In Cheyenne, Wyoming, we own a business office with approximately 13,400 square feet, and a service center and garage with an aggregate of approximately 28,300 square feet.

In addition to our owned properties, we lease the following properties:

Utilities Group:

- Approximately 22,200 square feet of office space in Rapid City, South Dakota;
- Approximately 8,800 square feet for a customer call center in Rapid City, South Dakota;
- Approximately 68,700 square feet of office space in Omaha, Nebraska; and
- Approximately 38,700 square feet for a customer call center in Lincoln, Nebraska.

Non-regulated Energy Group:

- Approximately 36,200 square feet of office space in Golden, Colorado.

Substantially all of the tangible utility properties of Black Hills Power and Cheyenne Light are subject to liens securing first mortgage bonds issued by Black Hills Power and Cheyenne Light, respectively.

Employees

At December 31, 2008, we had 2,122 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 group:

	Number of Employees
Corporate	573
Utilities	1,283
Non-regulated Energy	266
Total	2,122

At December 31, 2008, 686, or 32% of our employees (all within the Utilities Group), were covered by collective bargaining agreements, including:

Subsidiary	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	175	IBEW Local 1250	March 31, 2009
Cheyenne Light	69	IBEW Local 111	June 30, 2011
Colorado Electric	162	IBEW Local 667	April 17, 2010
Iowa Gas	137	IBEW Local 204	April 27, 2010
Kansas Gas	23	Communications Workers of America, AFL-CIO Local 6407	December 31, 2011
Nebraska Gas	120	IBEW Local 244	December 31, 2009

At December 31, 2008, approximately 23% of our Utilities Group employees were eligible for retirement or early retirement.

ITEM 1A. RISK FACTORS

The following 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 our forward-looking statements.

The recent global financial crisis has made the credit markets less accessible and created a shortage of available credit. We may, therefore, be unable to obtain the financing needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the Federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices and general economic and market conditions.

Recent financial distress within the global economy has caused significant disruption in the credit markets. Among other things, long-term interest rates on debt securities have increased significantly and the volume of equity and debt security issuances has decreased. Recent actions taken by the United States government, the Federal Reserve and other governmental and regulatory bodies may be insufficient to stabilize these markets. The longer such conditions persist, the more significant the implications become for us, including the possibility that adequate capital may not be available (or available on reasonable commercial terms) for us to refinance indebtedness remaining under the Acquisition Facility. In addition, on behalf of Enserco we are seeking to replace the existing uncommitted Enserco Facility with a committed credit line, also secured by Enserco s assets, to maintain credit support for the purchase and sale of natural gas and crude oil, including the issuance of letters of credit. If we are unable to timely refinance the Acquisition Facility or further extend its December 29, 2009 maturity date or replace the existing uncommitted Enserco Facility with a committed credit line, or both, we could be required to consider additional measures to conserve or raise capital. Among other things, alternatives could include deferring portions of our planned capital expenditure program, selling assets, issuing equity, reducing or eliminating our dividend, or curtailing certain business activities, including our marketing operations. Moreover, if we cannot complete capital conservation or capital raising alternatives at sufficient levels on a timely basis, we may not be able to repay the Acquisition Facility on the December 29, 2009 maturity date. The failure to consummate these anticipated refinancings, and any actions taken in lieu of such refinancings, could have a material adverse effect on our results of operations, cash flows and financial condition.

In addition, given that we are a holding company and that our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of market conditions then-prevailing, prudent financial management and any applicable regulatory requirements.

The recent global financial crisis has also increased our counterparty credit risk.

As a consequence of the global financial crisis, the creditworthiness of many of our contractual counterparties (particularly financial institutions) has deteriorated. As the creditworthiness of our counterparties deteriorates, we face increased exposure to counterparty credit default.

We have established guidelines, controls and limits to manage and mitigate credit risk. 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 parent company guarantees, prepayments, letters of credit and other security agreements. Although we aggressively monitor and evaluate changes in our counterparties credit status and adjust the credit limits based upon changes in the customer s creditworthiness, our credit guidelines, controls and limits may not protect us from increasing counterparty credit risk under today s stressed financial conditions. To the extent the financial crisis causes our credit exposure to contractual counterparties to increase materially, such increased exposure could have a material adverse effect on our results of operations, cash flows and financial condition.

National and regional economic conditions may cause increased late payments and uncollectible accounts, which would reduce earnings and cash flows.

A prolonged recession may lead to an increase in late payments from retail and commercial utility customers, as well as our non-utility customers (including marketing counterparties). If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

We may not be able to effectively integrate the utility operations acquired from Aquila into our existing businesses and operations, or achieve the anticipated results of the Aquila Transaction.

We expect the Aquila Transaction to produce various benefits. Achieving the anticipated benefits of the acquisition is subject to a number of uncertainties, such as pending and future rate cases, operational and financial synergies and our ability to receive regulatory approval from the CPUC for our proposed construction of rate-based generation to meet the long-term energy supply needs of our Colorado Electric customers. We cannot provide assurance that the businesses we acquired from Aquila will be integrated in an efficient and effective manner or that they will be profitable after our integration efforts have been completed.

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.

Our issuer credit rating is Baa3 (stable outlook) by Moody s; BBB- (stable outlook) by S&P; and BBB (stable outlook) by Fitch. Although we believe the IPP Transaction and Aquila Transaction have strengthened our financial profile and creditworthiness, we cannot assure that our credit ratings will not be lowered. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt (including the Acquisition Facility) and to complete new financings on acceptable terms, or at all. A downgrade could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and are, therefore, not recoverable.

Our regulated electricity and natural gas utility operations are subject to cost-of-service regulation and earnings oversight. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our gas and electric utilities in South Dakota, Wyoming, Colorado, Montana, Nebraska, Iowa and Kansas are permitted to recover certain costs (such as increased fuel and purchased power costs, as applicable) without having to file a rate case. To the extent we pass through such costs to our customers and a state public utility commission subsequently determines that such costs should not have been paid by the customers, we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could negatively affect our revenues, cash flows and results of operations.

We could incur additional and substantial write-downs of the carrying value of our natural gas and oil properties, which would adversely impact our earnings.

We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current spot prices and costs, as of the end of the appropriate quarterly period, are used. Such prices and costs are utilized except when different prices and costs are fixed and determinable from applicable contracts for the remaining term of those contracts. Two primary factors in the ceiling test are natural gas and oil reserve levels and current spot oil and gas prices, both of which impact the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves, or an increase or decrease in prices, can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense.

We recorded non-cash impairment charges in the fourth quarter of 2008 due to the full cost ceiling limitations in an amount of $59.0 million after-tax and we may have to record additional non-cash impairment charges in 2009 if current commodity prices persist. See Note 12 to Consolidated Financial Statements in this Annual Report on Form 10-K. The SEC recently adopted new reporting and accounting requirements for oil and gas companies that will change the way we test for potential ceiling test impairments (i.e., testing will be based on 12-month average commodity prices rather than a single date spot price as of the test date). The new requirements are effective January 1, 2010 and are proposed to apply to the Annual Report on Form 10-K for 2009.

We have deferred a substantial amount of gain associated with the assets sold in the IPP Transaction. If the Internal Revenue Service successfully challenges this deferral, our results of operations, financial position or liquidity could be adversely affected.

We expect to defer tax payments of approximately $185 million as a result of the IPP Transaction and the Aquila Transaction. We cannot be certain that the IRS will accept our position. If the IRS successfully sought to assert a contrary position, we could be required to pay a significant amount of these deferred taxes earlier than currently forecasted.

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 may 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. The SEC has proposed revised reporting guidelines for reserves that will apply to the Annual Report on Form 10-K for the period ending December 31, 2009, however there is the possibility of delaying the compliance date until the FASB has issued final accounting standards in line with the revised SEC rules. Key revisions include changes to the oil and gas pricing used to estimate reserves, the use of new technology for determining reserves and authorization for optional disclosure of probable and possible reserves.

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 reserve estimates. 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.

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;

Our inability to successfully integrate any businesses we acquire;

Our inability to retain management or other key personnel;

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;

Pipeline capacity and 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 are subject to a number of uncertainties, many of which are beyond our control. 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.

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 and labor disputes;

Capital and operating costs to comply with increasingly stringent environmental laws and regulations;

Opposition by members of public or special-interest groups;

Weather interferences;

Unexpected engineering, environmental and geological problems; and

Unanticipated cost overruns.

The ongoing operation of our facilities involves many 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, including 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.

Our operating results can be adversely affected by milder weather.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, and demand for natural gas is extremely sensitive to winter weather effects on heating requirements. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon winter weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler in the summer and warmer in the winter. Unusually mild summers and winters therefore could have an adverse effect on our financial condition and results of operations.

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, among other things, fuel prices, transmission constraints, supply and demand, weather, general economic conditions, and the rules, regulations and actions of 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 oil and natural gas 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 and prices for these items have increased significantly.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results.

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 may be essentially unchanged from the dates the transactions were consummated.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the adverse effects resulting from changes in natural gas and crude oil commodity prices, and interest and foreign exchange rates by using derivative financial instruments and other hedging mechanisms and by the activities we conduct in our trading operations. To the extent that we hedge our commodity price and interest rate exposures, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, our hedging and trading activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Our Energy Marketing and Utility operations rely on storage and transportation assets owned by third parties to satisfy their obligations.

Our energy marketing operations involve contracts to buy and sell natural gas, crude oil and other commodities, many of which are settled by physical delivery. We depend on pipelines and other storage and transportation facilities owned by third parties to satisfy our delivery obligations under these contracts. Our Gas Utilities also rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to ratepayers and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations 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, or for penalties imposed by state regulatory authorities.

Our business is subject to substantial governmental regulation and permitting requirements as well as environmental liabilities, including those we assumed in connection with certain acquisitions. We may be adversely affected if we fail to achieve or maintain compliance with existing or future regulations or requirements, or by the potentially high cost of complying with such requirements or addressing environmental liabilities.

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, which can require significant capital expenditure and operating costs. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of penalties, liens or fines, claims for property damage or personal injury, or environmental clean-up costs. In addition, existing regulations may be revised or reinterpreted, and new laws and regulations may be adopted or become applicable to us or our facilities, which could require additional unexpected expenditures and have a detrimental effect on our business.

In connection with certain acquisitions, we assumed liabilities associated with the environmental condition of certain properties, regardless of when such liabilities arose, whether known or unknown, and in some cases agreed to indemnify the former owners of those properties for environmental liabilities. Future steps to bring our facilities into compliance or to address contamination from legacy operations, if necessary, could be expensive and could adversely affect our results of operation and financial condition. We expect our environmental compliance 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 number of assets we operate.

Federal and state laws concerning climate change and air emissions, including emission reduction mandates and renewable energy portfolio standards, may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming, Colorado and Idaho. We are constructing another fossil-fuel generating plant in Wyoming. Air emissions of fossil-fuel generating plants are subject to federal, state and tribal regulation. Recent changes in federal and state laws governing air emissions from fossil-fuel generating plants will result in more stringent emission limitations. As the issue of climate change, particularly with respect to CO_2 and other greenhouse gas emissions by fossil-fuel generating plants, receives increased attention, additional or more stringent emission limitations or other requirements could be imposed. These limitations or other requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets and the closure of certain generating facilities. To the extent our regulated fossil-fuel generating plants are included in rate base, we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by our non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

We own electric utilities that serve customers in Colorado, Montana, South Dakota and Wyoming. To varying degrees, Colorado and Montana have each adopted mandatory renewable portfolio standards that require electric utilities to supply a minimum percentage of the power delivered to customers from renewable resources (e.g., wind, solar, biomass) by a certain date in the future. These renewable energy portfolio standards have increased the power supply costs of our electric operations. If these states increase their renewable energy portfolio standards, or if similar standards are imposed by the other states in which we operate electric utilities, our power supply costs will further increase. Although we will seek to recover these higher costs in rates, any unrecovered costs could have a material negative impact on our results of operations and financial condition.

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, including enforcement actions under the EPA s New Source Review rule, highlight the environmental risks faced by generating facilities, in general, and coal-fired generating facilities in particular.

Our energy production, transmission and distribution activities involve numerous risks that may result in accidents and other operating risks and costs.

Inherent in our natural gas distribution activities, as well as our production, transportation and storage of crude oil and natural gas and our coal mining operations, are a variety of hazards and operating risks, such as leaks, blow-outs, fires, releases of hazardous materials, explosions and mechanical problems that could cause substantial adverse financial impacts. These events could result in injury or loss of human life, significant damage to property or natural resources (including public parks), 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. Particularly for our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be great.

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 our financial results.

Ongoing changes in the United States electric 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 the 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 limited 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 rely on cash distributions from our subsidiaries to make and maintain dividends and debt payments. Our subsidiaries may not be able or permitted to make dividend payments or loan funds to us.

We are a holding company. Our 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 state utility commissions in Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming. In connection with the Aquila Transaction, the settlement agreements or acquisition orders approved by the CPUC, NPSC, IUB and KCC provide that, among other things, (i) our utilities in those jurisdictions cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and (ii) neither Black Hills Utility Holdings nor any of its utility subsidiaries can extend credit to us except in the ordinary course of business and upon reasonable terms consistent with market terms. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including intercompany loans. If our utility subsidiaries are unable to pay dividends or advance funds to us as a result of these conditions, or if the ability of our utility subsidiaries to make dividends or advance funds to us is further restricted, it 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.

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 is required to attest 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. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

We have recorded a substantial amount of goodwill associated with the Aquila Transaction. Any significant impairment of our goodwill would cause a decrease in our assets and a reduction in our net income and shareholders equity.

We had approximately $359 million of goodwill on our consolidated balance sheet as of December 31, 2008. A substantial portion of the goodwill is related to the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would decrease assets and reduce net income. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including future business operating performance, changes in economic, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

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 2008.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

David R. Emery, age 46, 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 19 years of experience with us.

Garner M. Anderson, age 46, has been Vice President, Treasurer and Chief Risk Officer since October 2006. He served as Vice President and Treasurer since July 2003. Mr. Anderson has 20 years of experience with us, including positions as Director Treasury Services and Risk Manager.

Roxann R. Basham, age 47, 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 25 years of experience with us.

Jeffrey B. Berzina, age 36, has been our Vice President Finance since November 2008. He served as Assistant Controller from 2004 to 2008, and Director of Financial Reporting from 2002 to 2004. Mr. Berzina has 8 years of experience with us. Prior to joining us, he had six years of experience in public accounting.

Scott A. Buchholz, age 47, has been our Senior Vice President Chief Information Officer since the close of the Aquila acquisition in July 2008. Prior to joining us, he was Aquila s Vice President of Information Technology from June 2005 until July 2008, Six Sigma Deployment Leader/Black Belt from January 2004 until June 2005, and General Manager, Corporate Information Technology from February 2002 until January 2004. He was employed with Aquila for 28 years.

Anthony S. Cleberg, age 56, has been Executive Vice President and Chief Financial Officer since July 2008. He was an independent investor, developer and consultant with companies in Colorado and Wyoming from 2002 until joining us in 2008. Prior to his consulting role, he was the Executive Vice President and Chief Financial Officer of two publicly-traded companies: Washington Group, International, Inc. a large engineering and construction company involved in power plant construction and mining operations, and Champion Enterprises, a builder of factory-built housing. Before his CFO roles, he spent 15 years in various senior financial positions with Honeywell International, Inc. and eight years in public accounting at Deloitte & Touche, LLP.

Linden R. Evans, age 46, 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 7 years of experience with us.

Steven J. Helmers, age 52, 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 8 years of experience with us.

Richard W. Kinzley, age 43, has been our Vice President, Strategic Planning and Development since September 2008 and Director of Corporate Development from 2000 until September 2008. Mr. Kinzley has 9 years of experience with us. Prior to joining us, he had 9 years of experience in public accounting and 2 years of experience in industry.

Perry S. Krush, age 49, has been Vice President Controller since December 2004. Mr. Krush has 20 years of experience with us, including positions as Controller Retail Operations from 2003 to 2004, Director of Accounting for our subsidiary, now known as Black Hills Non-regulated Holdings and Accounting Manager Fuel Resources from 1997 to 2003.

James M. Mattern, age 54, 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 21 years of experience with us.

Robert A. Myers, age 51, has been our Senior Vice President Human Resources since January 2009 and served as our Interim Human Resources Executive since June 2008. He was a partner with Strategic Talent Solutions, a human resources consulting firm, from October 2006 until December 2008, Senior Vice President Chief Human Resource Officer for Devon Energy from March 2006 until September 2006, and Senior Vice President and Chief Human Resource Officer at Reebok International, Ltd from November 2003 until January 2006. He has over 28 years of service in key human resources leadership roles.

Thomas M. Ohlmacher, age 57, 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 34 years of experience with us.

Kyle D. White, age 49, has been Vice President Corporate Affairs since January 2001 and Vice President Marketing and Regulatory Affairs since July 1998. Mr. White has 26 years of experience with us.

Lynnette K. Wilson, age 49, has been our Senior Vice President Communications and Investor Relations since the close of the Aquila acquisition in July 2008. Prior to joining us, she was Aquila s Vice President of Communications and Investor Relations from June 2006 until July 2008 and Issues Strategist for the Office of the Chairman and Chief Executive Officer from January 2002 until May 2006. She was employed with Aquila for 9 years.

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 December 31, 2008, we had 4,830 common shareholders of record and approximately 14,000 beneficial owners, representing all 50 states, the District of Columbia and 6 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 30, 2009 meeting, our Board of Directors declared a quarterly dividend of $0.355 per share, equivalent to an annual dividend of $1.42 per share, marking 2009 as the 39th consecutive annual dividend increase for the Company.

For additional discussion of our dividend policy and factors that may limit our ability to pay dividends, see Liquidity and Capital Resources under Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

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

Year ended December 31, 2008	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
Dividends paid per share	$	0.35	$	0.35	$	0.35	$	0.35
Common stock prices								
High	$	43.98	$	39.66	$	39.23	$	31.59
Low	$	33.21	$	31.70	$	30.10	$	21.73

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	$	39.63	$	42.59	$	44.48	$	45.41
Low	$	35.40	$	36.86	$	36.84	$	40.21

UNREGISTERED SECURITIES ISSUED DURING 2008

On December 19, 2008, we issued the following unregistered securities as additional earn-out consideration associated with the acquisition of Indeck on July 7, 2000, pursuant to an arbitrator s ruling. The unregistered securities were issued under Rule 506 of Regulation D of the Securities Act of 1933. No additional consideration was received in exchange for the earn-out shares.

Stockholder	Common Shares Issued
Gerald R. Forsythe	88,251
John W. Salyer	17,080
Michelle R. Fawcett	9,252
Marsha Fournier	9,252
Monica Breslow	9,252
Melissa S. Bernadette	9,252
	142,339

No other unregistered securities were sold during 2008, except as were previously reported in our periodic and current reports to the SEC.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased(1)	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, 2008 - October 31, 2008	39	$ 25.25		
November 1, 2008 - November 30, 2008	356	$ 25.51		
December 1, 2008 - December 31, 2008	2,644	$ 24.99		
Total	3,039	$ 25.05		

(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.

ITEM 6. SELECTED FINANCIAL DATA

Certain items related to 2007 through 2004 have been restated from prior year presentation to reflect the classification of the 2008 IPP Transaction as discontinued operations (see Notes 1 and 16 to Consolidated Financial Statements).

Years Ended December 31,	2008	2007	2006	2005	2004
Total Assets (in thousands)	$ 3,379,889	$ 2,469,634	$ 2,241,798	$ 2,120,258	$ 2,029,585
Property, Plant and Equipment (in thousands)					
Total property, plant and equipment	$ 2,705,492	$ 1,847,435	$ 1,661,028	$ 1,351,366	$ 1,142,537
Accumulated depreciation and depletion	(683,332)	(509,187)	(462,557)	(407,039)	(366,356)
Capital Expenditures in thousands)	$ 1,304,352	$ 267,047	$ 308,450	$ 208,856	$ 90,974
Capitalization (in thousands)					
Current maturities	$ 2,078	$ 130,326	$ 4,249	$ 4,237	$ 4,026
Notes payable	703,800	37,000	145,500	55,000	24,000
Long-term debt, net of current maturities	501,252	503,301	554,411	558,725	536,834
Preferred stock equity					7,167
Common stock equity	1,050,536	969,855	790,041	738,879	728,598
Total capitalization	$ 2,257,666	$ 1,640,482	$ 1,494,201	$ 1,356,841	$ 1,300,625
Capitalization Ratios					
Short-term debt, including current maturities	31.3%	10.2%	10.0%	4.4%	2.1%
Long-term debt, net of current maturities	22.2	30.7	37.1	41.2	41.3
Preferred stock equity					0.6
Common stock equity	46.5	59.1	52.9	54.4	56.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues (in thousands)	$ 1,005,790	$ 574,838	$ 542,585	$ 496,768	$ 325,388
Net Income (Loss) Available for Common (in thousands):					
Utilities	$ 43,904	$ 31,633	$ 24,188	$ 20,119	$ 19,209
Non-regulated Energy	(23,475) [(1)]	49,520	36,588	43,167	29,003
Corporate expenses and intersegment eliminations	(72,596) [(2)]	(5,872)	(5,514)	(13,491)	(3,790)
Income (Loss) from Continuing Operations Before Changes in Accounting Principles	(52,167)	75,281	55,262	49,795	44,422
Discontinued operations [(3)]	157,247	23,491	25,757	(16,375)	13,551
Preferred dividends				(159)	(321)
	$ 105,080	$ 98,772	$ 81,019	$ 33,261	$ 57,652
Dividends Paid on Common Stock (in thousands)	$ 53,663	$ 50,300	$ 43,960	$ 42,053	$ 40,210
Common Stock Data [(4)] (in thousands)					
Shares outstanding, average	38,193	37,024	33,179	32,765	32,387
Shares outstanding, average diluted	38,193	37,414	33,549	33,288	32,912
Shares outstanding, end of year	38,636	37,796	33,369	33,156	32,478
Earnings (Loss) Per Share of Common Stock [(4)] (in dollars)					
Basic earnings (loss) per average share -					
Continuing operations	$ (1.37)	$ 2.03	$ 1.67	$ 1.52	$ 1.37
Discontinued operations	4.12	0.63	0.77	(0.50)	0.41
Total	$ 2.75	$ 2.66	$ 2.44	$ 1.02	$ 1.78

Diluted earnings (loss) per average share -					
Continuing operations	$ (1.37)	$ 2.01	$ 1.65	$ 1.49	$ 1.35
Discontinued operations	4.12	0.63	0.77	(0.49)	0.41
Total	$ 2.75	$ 2.64	$ 2.42	$ 1.00	$ 1.76
Dividends Paid per Share	$ 1.40	$ 1.37	$ 1.32	$ 1.28	$ 1.24
Book Value Per Share, End of Year	$ 27.19	$ 25.66	$ 23.68	$ 22.28	$ 22.43
Return on Average Common Stock Equity (year-end)	10.4%	11.2%	10.6%	4.5%	8.1%

Operating Statistics:

Years ended December 31,	2008	2007	2006	2005	2004
Generating capacity (MW):					
Utilities (owned generation)	630	435	435	435	435
Utilities (purchased capacity)	420	50	50	50	50
Independent power generation(5)	141	983	989	1,000	1,004
Total generating capacity	1,191	1,468	1,474	1,485	1,489
Electric Utilities:					
MWh sold:					
Retail electric	3,532,402	2,636,425	2,552,290	2,472,051	1,509,635
Contracted wholesale	665,795	652,931	647,444	619,369	614,700
Wholesale off-system	1,551,273	678,581	942,045	869,161	926,461
Total MWh sold	5,749,470	3,967,937	4,141,779	3,960,581	3,050,796
Gas Utilities:					
Gas Dth sold	23,053,599				
Transport volumes	26,805,075				
Oil and gas production sold (MMcfe)	13,534	14,627	14,414	13,745	12,595
Oil and gas reserves (MMcfe)	185,542	207,806	199,092	169,583	173,417
Tons of coal sold (thousands of tons)	6,017	5,049	4,717	4,702	4,780
Coal reserves (thousands of tons)	274,000	280,000	285,000	290,000	294,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,873,400	1,743,500	1,598,200	1,427,400	1,226,600
Crude oil physical sales (Bbls) (6)	7,880	8,600	8,800		

(1) Includes a $59.0 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2008.

(2) Includes a $61.4 million after-tax unrealized mark-to-market loss related to interest rate swaps.
(3) 2008 includes a $139.7 million after-tax gain on the IPP Transaction and 2005 includes long-lived asset impairment charges of approximately $33.9 million after-tax
(4) In February 2007, we issued 4.2 million shares of common stock, which dilutes our earnings per share in subsequent periods.
(5) Includes 825 MW in 2007, 2006 and 2005, and 839 MW in 2004, which have been reported as Discontinued operations.
(6) 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 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. We report for our business groups in the following financial segments:

Business Group	**Financial Segment**
Utilities	Electric Utilities
	Gas Utilities
Non-regulated Energy	Oil and Gas
	Power Generation
	Coal Mining
	Energy Marketing

Our Utilities Group consists of our Electric and Gas utility segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 202,100 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 33,300 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 524,000 natural gas customers in Colorado, Nebraska, Iowa and Kansas. Our Non-regulated Energy Group engages in the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts; and the marketing of natural gas, crude oil and related services.

Industry Overview

The United States energy industry experienced one of the most tumultuous years ever in 2008. Energy commodity prices, which were near historic highs in July with natural gas trading over $13 per Mcf and crude oil selling for nearly $150 per barrel, experienced dramatic declines to less than $6 and $45, respectively, by year end. Domestic energy prices continue to be influenced by global factors, including foreign economic conditions, especially in China and Asia, domestic economic conditions, the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions. Mild weather dominated the United States during much of the year, reducing demand for fuel used for power generation and heating.

Beginning in late summer, a slow down in the United States economy accelerated into one of the worst recessions since the 1930s. A global credit crisis emerged from a proliferation of sub-prime lending. As that issue attracted attention, other credit quality concerns surfaced, creating an international-scale financial crisis. The capital markets have been impacted dramatically by the crisis, severely inhibiting the ability of companies to raise both debt and equity capital, and significantly increasing the cost of capital.

Like other United States industries, the energy industry is faced with uncertainties, both short and long-term. Many utilities are faced with large capital spending needs over the next few years to replace aging infrastructure and add new assets such as transmission lines and renewable energy resources. Utility companies generally are less impacted by economic downturns, but a prolonged or severe recession could affect the demand for energy services and the ability of customers to pay their utility bills and restrict the ability of companies to obtain the capital necessary for infrastructure expansion.

The federal and state utility regulatory climate in 2008, in a general sense, remained relatively constructive among government, industry and consumer representatives. In the multi-state region encompassing 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 concerns through demand management and energy efficiency programs.

The November 2008 elections however, represented a significant change in the domestic political environment. Sweeping wins for Democrats in both Houses of Congress, signal a shift in domestic policy that will likely have dramatic impacts on the domestic energy industry. Despite all of the focus on the economy, environmental issues are slated to remain a priority for many in Congress. Federal legislation that would mandate renewable energy use and the reduction of greenhouse gas emissions appears likely to pass during this Congress in the form of a federal renewable portfolio standard, and a greenhouse gas reduction target, utilizing either a carbon tax or a carbon cap-and-trade system. These potential legislative actions could have significant macroeconomic consequences. The associated cost increase may cause a dramatic increase in consumers rates for electricity and other energy in the mid- to long-term. State legislatures were also active on environmental issues in 2008, with a majority of states now having adopted some form of renewable standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation.

Progress in the domestic energy industry in 2008 included increasing levels of oil and gas exploration and production activity, continued planning and construction of liquefied natural gas port facilities, proposals for additional gas-fired, coal-fired and nuclear power plants, planning for additional electric transmission capacity, and the advancement of renewable energy resources and utilization.

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 marketplace continues to respond to increased oversight and enforcement activity 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 cited the need for expanded energy capacity and delivery systems. They foresee an increase in capital investment across a wide spectrum of energy companies. Many electric and gas utilities must replace aging plant and equipment, and regulators appear to be willing to provide acceptable rate treatment for additional utility investment. Oil and gas producers will continue to explore for new reserves, particularly of natural gas, which will be the primary fuel of choice in an era of concern regarding greenhouse gas emissions. In the short-term, however, low oil and natural gas prices prompted companies to curtail projects as they seek to conserve cash in a constrained capital market environment. The increased focus on environmental regulation has made it increasingly more difficult to obtain drilling permits, particularly on public and Native American lands.

In early 2008, 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 considerably in response to a trend of lower overall natural gas prices. Fossil fuel combustion continues to be a contentious domestic and international public policy issue, as many nations, including United States 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, the State of California has mandated 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.

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. In that regard, the United States 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 and sequestration.

Energy providers, government authorities and private interests continue to address 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 requirements. In the short-term, prevailing economic conditions will reduce consumption. Despite public and private efforts to promote conservation and efficiency, however, the demand for energy is expected to increase steadily over the long term. To meet this demand growth, the industry will need to provide capital, resources and innovation to serve customers in cost-effective ways and to achieve suitable returns on investment.

The Company believes that it is well-positioned in this industry setting, and able to proceed with its key business objectives. Along with industry counterparts, we are preparing 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 may 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 carefully explored in public policy proceedings.

Business Strategy

We are a customer-focused integrated energy company. Our business is comprised of electric and natural gas utility operations; power generation; and fuel assets and services, including production and marketing operations for crude oil, natural gas and coal. Our focus on customers whether they are 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 energy operations, which range from fuel production to retail utility sales, reduces reliance on any single business segment to achieve our strategic objectives. It helps reduce our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long term. Despite very challenging conditions in the capital markets, we have sufficient liquidity and solid cash flows, and expect to be able to access the capital markets as needed. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and long term.

During 2008, we significantly transformed our business and reduced our risk profile through the acquisition of five utility properties, and the divestiture of seven IPP plants. For the next two years, we will focus on continued integration of the newly acquired utility properties and the achievement of certain synergies made possible by the utility acquisition. We expect to achieve operating synergies in accounting and information systems, procurement, inventory, utility engineering, power marketing, resource planning and other areas.

Our long-term strategy focuses on growing both our utility and non-regulated energy businesses, primarily by increasing our customer base and providing superior service to both utility and non-regulated energy customers.

In our natural gas and electric utilities, we intend to grow our asset base through customer growth in our existing utility service territories, combined with the construction of new rate-based power generation facilities. We also plan to pursue acquisitions of additional utility properties, primarily in the Great Plains and Rocky Mountain regions of the country. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure satisfactory rate recovery to provide solid economic returns on our utility investments.

In our fuel production operations, we will continue to prudently 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. Our ability to grow both production and reserves may be hindered in the short-term by low price levels for both crude oil and natural gas resulting from the impact on demand of a weakened economy. In the long-term, however, we believe that demand for natural gas will be strong. Given increased regulatory emphasis on wind and solar power generation, and potential greenhouse gas legislation that may limit construction of new coal-fired power plants, natural gas will be the fuel of choice for power generation. Additional gas-fired peaking resources will also be necessary to provide back-up supply for renewable technologies.

We will continue efforts to develop additional markets for our coal production, including the development of additional power plants at our mine site. Nearly 50% of all electricity generated in the United States is currently supplied from coal-fired plants, and it will take decades before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation s electric supply for the foreseeable future. Potential greenhouse gas legislation may limit construction of new conventional coal-fired power plants, but technologies such as carbon capture and sequestration should provide for the long-term economic use of coal. We will investigate the possible deployment of these technologies at our mine site in Wyoming.

We divested of seven IPP plants in 2008 because we were able to capture significant value for shareholders, but we are not exiting the non-regulated power generation business. We have expertise in permitting, constructing and operating power generation facilities; and these skills provide us with a key opportunity to add long-term shareholder value. We intend to grow our non-regulated power generation business by continuing to focus on long-term contractual relationships with other load-serving utilities.

The expertise of our energy marketing business should provide continued profitability through a risk-managed and disciplined approach to producer services, origination, storage, transportation and proprietary marketing strategies. We will also continue to utilize our marketing expertise to enhance the value of our other energy assets, particularly our fuel and power generation assets.

We intend to operate our lines of business as Utilities and Non-regulated Energy Groups. The Utilities Group consists of electric and natural gas utility assets and services. The Non-regulated Energy Group consists of fuel production, mid-stream assets, power generation facilities and energy marketing.

The following are key elements of our business strategy:

Complete the full, efficient integration of the five utility properties acquired in the 2008 Aquila Transaction, focusing on the achievement of operating synergies and cost reductions;

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities;

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

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

Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation businesses;

Selectively grow our non-regulated power generation business in targeted Western markets by developing assets and selling most of the capacity and energy production through mid-and long-term contracts primarily to load-serving utilities;

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

Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner;

Opportunistically 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 credit, price and operational risks inherent in buying and selling energy commodities; and

Maintain an investment grade credit rating and ready access to debt and equity capital markets.

Complete the full, efficient integration of the five utility properties acquired in the 2008 Aquila Transaction, focusing on the achievement of operating synergies and cost reductions. The July 14, 2008 acquisition of five utility properties in four states from Aquila significantly expanded our regional presence and the size and scope of our utility operations. The expanded utility operations will enhance our ability to serve customers and communities and build long-term value for our shareholders. Over the next two years, we will continue working diligently to integrate the operations of the five acquired utilities with our other utility operations. By standardizing processes, centralizing purchasing and inventory, and utilizing common computer systems for customer service, accounting, human resources and operations, it will be possible to reduce costs and improve operating efficiency.

Provide stable long-term rates for customers and increase earnings by efficiently planning, constructing and operating rate-base power generation facilities needed to serve our electric utilities. Our Company was originally 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 competitive 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. Since the generating assets are included in the utility rate base, customer rates are more stable than if the power was purchased from the open market via wholesale contracts. 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 January 2008 completion of Wygen II to serve the customers of Cheyenne Light and the ongoing construction of Wygen III to serve the customers of Black Hills Power. In August 2008, following the closing of the Aquila Transaction, we submitted to the Colorado regulators a long-term resource plan that included the proposed construction of up to five gas-fired power plants, with a total capacity of approximately 350 megawatts, to serve the customers of Colorado Electric. Hearings were completed in late January 2009, and on February 24, 2009 the Commission issued its initial decision. The decision allows us to construct 2 gas-fired power plants representing approximately 150 MW. We will issue a request for proposal for the remaining 200 MW with a bid due date in June 2009. Under the process outlined by the Commission in its decision, we may submit proposals to provide generation through our IPP business. This initial Commission decision and order is subject to requests by any party to the proceeding for reconsideration by the Commission, which must be filed by March 16, 2009.

Proactively integrate alternative and renewable energy into our utility energy supply while remaining mindful of potential customer rate impacts. The energy and utility industries face tremendous uncertainty related to the potential impact of legislation intended to reduce 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 of renewable energy use. 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 is also under consideration.

Mandates for the use of renewable energy or the reduction of greenhouse gas emissions will likely result in substantial increases in the prices for electricity and natural gas. At the same time, however, as a regulated utility we are responsible for providing safe, reasonably priced, reliable sources of energy to our customers. As a result, we have developed a customer-centered strategy for renewable energy standards and greenhouse gas emission reductions that balances our customers rate concerns with environmental considerations. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize rate increases for our utility customers. Examples of our balanced approach include:

With respect to states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have nevertheless integrated cost-effective renewable energy into our generation supply on the expectation that there will be mandatory renewable energy standards in the future. For example, in September 2008, we commenced buying wind energy for use at Black Hills Power and Cheyenne Light under a 20-year power purchase agreement for approximately 30 MW of wind energy located in Cheyenne, Wyoming;

In states such as Colorado and Montana that do have a legislative mandate on the use of renewable energy, we are aggressively pursuing cost-effective initiatives with the regulators that will allow us to accomplish our renewable energy requirements. In Colorado for instance, we recently filed an electric resource plan that includes enough renewable energy additions and greenhouse gas emission reductions to permit us to satisfy both (i) the State s requirement that 20% of a utility s distributed energy must be supplied by renewable energy resources by 2020 and (ii) the governor s executive order that requires a 20% reduction in carbon dioxide emissions; and

In all states in which we conduct electric operations, we are exploring other potential biomass, solar and wind energy projects and evaluating other potential wind generator sites, particularly sites located near our utility service territories.

Using reasonable assumptions, we have also 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. For customers in states without renewable or CO_2 mandates, such as South Dakota and Wyoming, we believe it is still in our utility customers long-term interest to construct new mine-mouth, coal-fired generating facilities, such as our Wygen II generation facility (completed in January 2008) and our Wygen III generation facility (under construction). In addition, we are actively evaluating alternative coal-fired generation technologies, including IGCC and carbon capture and sequestration, though both appear cost prohibitive in the near term. These technologies may become cost effective in the future if the cost of CO_2 emissions reaches sufficiently high levels or further technological advancements reduce the costs of those technologies.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For 125 years, we have provided strong utility services, delivering quality and value to our customers. Our tradition of accomplishment supports 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, community involvement and a relationship-based approach to regulatory matters. The 2005 acquisition of Cheyenne Light and the 2008 Aquila Transaction 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.

Although we do not expect to make any significant utility acquisitions in 2009, some industry experts believe that the current financial turmoil and economic recession may produce opportunities for healthy utility companies to acquire utility assets and operations of less creditworthy companies upon attractive terms and conditions. We would expect to consider such opportunities if we believe they would further our long-term strategy and help maximize shareholder value.

Build and maintain strong relationships with wholesale power customers of both our utilities and non-regulated power generation business. We strive to build strong relationships with other utilities, municipalities and 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 help our customers meet their 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. In addition, relationships that we ve established with wholesale power customers have developed into other opportunities. MEAN and MDU, both wholesale power customers, will now also be our joint owners in power plants.

Selectively grow our non-regulated power generation business in targeted Western markets by developing assets and selling most of the capacity and energy production through mid-and long-term contracts primarily to load-serving utilities. In late 2007, we initiated an evaluation of the merits of divesting certain power generation assets. That strategic review resulted in the mid-2008 divestiture of seven IPP plants for a total of $840 million. While much of our recent power plant development has been for our regulated utilities, we intend to continue to expand our non-regulated power generation business by 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 marketing capabilities. We intend to grow this business through a combination of disciplined acquisitions and the development of new power generation facilities primarily in the western region where our detailed knowledge of market and electric transmission fundamentals gives us a competitive advantage, and, in turn, increases our ability to earn attractive returns. We expect to prioritizesmall-scale facilities that serve incremental growth, and are relatively easier to permit and construct than large-scale generation projects.

Most of the energy and capacity from our non-regulated power facilities is sold 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. Going forward, we will continue to focus on selling a majority of our unregulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions.

With respect to our current power sale agreements, two of our long-term power contracts expire in 2011 and 2013. These contracts provide for the sale of capacity and energy to Cheyenne Light from our Gillette CT and Wygen I plants, respectively. As part of our integrated resource planning efforts, a decision will be made regarding whether or not to extend or replace the contracts. 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 which have 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 be competitive as a power generator. 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 industry benchmarks. We aggressively manage each of these factors with the goal of achieving low production costs.

One of our primary competitive advantages is our WRDC coal mine, which is located in reasonably close proximity to our electric utility service territories. We attempt to exploit this competitive advantage by building additional mine-mouth coal-fired generating capacity, which allows us to substantially eliminate fuel transportation and storage costs. This strengthens our position as a low-cost producer because transportation costs often represent the largest component of the delivered cost of coal for many other utilities.

Grow our reserves and increase our production of natural gas and crude oil in a cost-effective manner. Our strategy is to cost- effectively grow our reserves and increase our production of natural gas and crude oil through both organic growth and acquisitions. While consistent growth remains our objective, we realize the necessity of managing for value over managing for growth and intend to be appropriately responsive to market conditions. Growth in our core areas in the Rocky Mountain region is a focus that we must balance with opportunities in plays or basins which are new to us. In the short-term, growth plans may be negatively impacted by the current economic crisis, and low crude oil and natural gas prices. In the long-term, however, we believe that demand will lead to higher product prices and opportunity for growth. Specifically, we plan to:

Primarily focus on lower-risk development and exploratory drilling;

Participate on a non-operated basis with other operators to provide exposure to additional plays and producing basins;

Focus on various plays in the Rocky Mountain region, where we can more easily integrate 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.

Opportunistically 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 United States with marketing and transporting their crude oil and 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 credit, price and operational risks inherent in buying and selling energy commodities. All of 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. Our oil and gas, power generation and 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, particularly for our marketing operations. We have oversight committees that monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining a credit facility separate from our corporate facility. We had no counterparty credit losses in 2008 despite the economic turmoil.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital will be critical to our future success. We will require access to the capital markets to fund our planned capital investments or, when possible, to make strategic acquisitions that prudently grow our businesses.

In 2008, disruption in worldwide capital markets was evidenced by diminished liquidity in the debt capital markets, significant write-offs in the financial services sector, the re-pricing of credit risk, and the failure of certain financial institutions. Despite actions of the United States federal government, these events have contributed to a general economic decline that is materially and adversely impacting the broader financial and credit markets, and reducing the availability of debt and equity capital. Our acquisition of additional utility properties in 2008, combined with the divestiture of seven IPP plants, has lowered our overall corporate risk profile. Even so, our access to capital markets could be impacted by the conditions described above. Our access to adequate and cost-effective financing also depends upon our ability to maintain our investment grade issuer credit rating.

Notwithstanding these adverse market conditions, in late 2008 we extended the maturity date on the Acquisition Facility that was used to fund our purchase of utility properties from Aquila. The Acquisition Facility now expires on December 29, 2009. We anticipate that we will replace the Acquisition Facility with long-term financing in 2009.

Prospective Information

We expect long-term growth through the expansion of integrated, balanced and diverse energy operations. We recognize that sustained growth requires near continual capital deployment. The current condition of the capital markets will make it challenging to execute our strategy in the short-term, but we are confident in our ability to obtain the necessary financing to continue our growth plans. We are proactively taking prudent actions to modify our short-term plans to address the current capital market uncertainties. We will remain focused on managing our operations cautiously and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Utilities Group

The Aquila Transaction significantly broadened our regional utility presence, more than doubled our employee count and resulted in a five-fold increase in our utility customer base. Post-close integration activities are being executed so that over the next 18 to 24 months, our workforces and systems will be combined to establish a platform upon which to continue growing our business and delivering value to our shareholders.

Electric Utilities

Business at Black Hills Power remained strong in 2008. We began construction of the Wygen III power plant, which is planned for commercial operation by mid-2010. Black Hills Power is expected to own 75% of the facility s capacity as MDU has elected to purchase a 25% ownership interest in the facility. Beginning January 1, 2009 we will benefit from newly increased transmission rates resulting from a recent FERC transmission rate case. The new rate structure also includes a formula approach to rates that will allow us to recover our capital investment as the capital is spent on the related transmission infrastructure. To accommodate both the load growth within the region and the addition of Wygen III, additional transmission infrastructure is planned over the next several years.

We are focused on Colorado Electric s pending Energy Resource Plan that has been proposed to the CPUC. Among other matters, the resource plan addresses the replacement of a purchased power agreement with PSCo that currently supplies approximately 75% of Colorado Electric s annual energy and capacity needs and expires at the end of 2011. The resource plan proposes the construction of up to five gas-fired power plants to be placed in service at the beginning of 2012. The addition of any of these plants to our utility rate base would have a significant positive impact on our financial results.

Gas Utilities

Our Gas Utilities are focused on the continued investment and strengthening of our gas distribution system, which grows our utility rate base. As further described in our Utilities Group Regulation and Rates discussion within Item 1 and 2 Business and Properties, we have pending rate cases for Iowa Gas and Colorado Gas. Interim rates have been put in place in Iowa and conclusion is expected for both cases during 2009.

Non-regulated Energy Group

Power Generation

During January 2009, we completed the sale of a 23.5% interest in Wygen I to MEAN for $51.0 million. We recognized a gain on the sale of approximately $16.7 million after-tax. Concurrently with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 MW of power and capacity from Wygen I. The decreased revenues associated with the terminated agreement will be partially replaced by agreements under which MEAN will pay for costs associated with administrative services, plant operations and coal supplied by our Coal Mining operation.

We plan to continue evaluating opportunities to bid generation resources, both new and existing, into the requests for proposals of other regional electric utilities for their energy and capacity needs.

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. Total annual production is estimated to be approximately 6.0 million tons in 2009, and increase by approximately 0.6 million tons per year to serve the needs of the Wygen III plant in 2010.

We experienced higher operating expenses in 2008 in part due to high diesel fuel costs. While we expect to see lower prices for diesel fuel in 2009 this benefit will likely be offset by an increase in overburden production associated with the high overburden ratios in the current phase of our mine plan.

Oil and Gas

We are focused on growing our oil and gas production through development of existing acreage and limited acquisitions based on economic and industry conditions. During 2009, we expect to limit our development capital to no more than the cash flows produced by our oil and gas properties. The current economic conditions will be particularly challenging since low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures. The lower development capital expenditures will lead to lower production levels due to the natural production decline of existing wells.

At December 31, 2008 we recorded a $59.0 million after-tax ceiling test impairment charge to our oil and gas properties. If the early 2009 low commodity price environment continues, we will likely incur an additional significant non-cash ceiling test impairment charge as early as the first quarter of 2009.

Energy Marketing

We have a strong marketing portfolio with a significant amount of economic value that will be realized as the transactions settle over the next several years. The addition of more long-term transportation and storage contracts during 2008 has extended the duration of our marketing book. While we expect to derive earnings from these contracts over many years, the required methods of accounting for these transactions could result in additional earnings volatility during the term of these contracts. Our 2008 earnings were positively impacted by unrealized mark-to-market gains that accelerated margins into 2008 from proprietary positions that will not settle until 2009 and 2010.

We are currently pursuing a renewal of our uncommitted Enserco Facility prior to its May 8, 2009 expiration. We intend to seek a committed facility to replace the current uncommitted facility. Given the current condition of the credit markets, until we renew the Enserco Facility and refinance certain of our other short-term debt, we will conduct our Enserco business operation in a manner to preserve liquidity, which includes minimizing utilization of the Enserco facility. This constraint on capital could restrict Enserco s ability to take advantage of favorable transactions that may be available in the marketplace.

Corporate

We currently have interest rate swaps with a notional amount of $250.0 million, which no longer qualify for hedge accounting treatment provided by SFAS 133. Accordingly, all mark-to-market adjustments on these swaps are recorded through the income statement. As of December 31, 2008, these swaps had a fair value of $(94.4) million which was recorded as an unrealized mark-to-market loss in our 2008 earnings. Fluctuations in interest rates create volatility in the fair value of these swaps which will likely have a significant impact on our 2009 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement.

Results of Operations

Executive Summary

Loss from continuing operations for the year 2008 was impacted by a $59.0 million after-tax non-cash charge for a ceiling test impairment of oil and gas assets due to low crude oil and natural gas prices at the end of 2008, lower margins from the Energy Marketing segment and a $61.4 million after-tax mark-to-market loss related to Corporate interest rate swaps no longer designated as hedges for accounting purposes. Solid utility performance and increased earnings from the Power Generation segment partially offset the earnings decline. Results also reflect the impacts of the IPP Transaction and the Aquila Transaction.

Earnings for the Utilities increased 39% over the prior year. Earnings were impacted by the July 14, 2008 purchase date of the five utilities acquired in the Aquila Transaction, a rate increase effective at Cheyenne Light January 1, 2008 and increased MWh sales. Partially offsetting the increases were higher maintenance and depreciation costs associated with the 95 MW coal-fired Wygen II plant, placed in commercial service January 1, 2008, and lower AFUDC.

Lower earnings from Energy Marketing were primarily attributable to a $69.3 million pre-tax decrease in realized marketing margins. Earnings were impacted by market conditions affecting both transportation and storage strategies as well as the effect of lower commodity prices on oil marketing margins. Partially offsetting these decreases was a $34.8 million increase in unrealized marketing margins.

Power Generation s improved earnings for 2008 are a result of increased earnings from equity investments as compared to 2007 and increased earnings from the Gillette CT primarily due to lower gas and purchased power costs and maintenance expense. The increase to earnings also reflects the impacts of a $1.8 million after-tax impairment charge for the Ontario plant and a $0.4 million after-tax charge for a goodwill impairment in 2007, higher allocated indirect corporate costs related to the IPP Transaction and not reclassified to discontinued operations and lower investment partnership earnings, primarily as a result of a partnership impairment charge of the Glenns Ferry and Rupert power plants in 2007.

Oil and Gas segment earnings decreased primarily as a result of the $59.0 million after-tax ceiling test impairment charge, a 7% decrease in production, and increased LOE and depletion costs. Revenues increased due to a 32% increase in the average hedged price of oil received and a 1% increase in the average hedged price of gas received, partially offset by production decreases.

Coal Mining earnings decreased due to increased overburden expense, diesel fuel costs, depreciation expense and higher mineral taxes and royalties due to increased revenues and tons sold. Revenues increased due to a 19% increase in tons of coal sold at a higher average price.

Overview

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

	2008	2007	2006
Revenue:			
Utilities	$ 749,250	$ 301,514	$ 323,003
Non-regulated Energy	256,540	273,324	219,536
Corporate			46
	$ 1,005,790	$ 574,838	$ 542,585

	2008	2007	2006
Income (loss) from continuing operations:			
Utilities	$ 43,904	$ 31,633	$ 24,188
Non-regulated Energy	(23,475)	49,520	36,588
Corporate	(72,596)	(5,872)	(5,514)
	$ (52,167)	$ 75,281	$ 55,262

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.

In February 2007, we entered into a definitive agreement with Aquila to acquire its regulated electric utility assets in Colorado and its regulated gas utilities in Colorado, Nebraska, Iowa and Kansas for $940 million, subject to customary closing adjustments. On July 14, 2008, we completed the acquisition. The purchase price was financed through a $383 million borrowing on our $1 billion acquisition credit facility and from cash proceeds generated from our IPP Transaction, which was completed on July 11, 2008. The results of operations for the acquired utilities have been included in the accompanying Consolidated Financial Statements from the date of acquisition.

Discontinued operations in 2008, 2007 and 2006 represent the results of operations and gain on sale from the IPP Transaction and the March 2006 sale of our crude oil marketing and transportation business.

<u>2008 Compared to 2007</u>

Consolidated loss from continuing operations for 2008 was $52.2 million, or $(1.37) per share, compared to earnings of $75.3 million, or $2.01 per share, in 2007. Income from discontinued operations was $157.2 million, or $4.12 per share, compared to income of $23.5 million, or $0.63 per share in 2007 and includes a $139.7 million gain on the sale of the operating assets from the IPP Transaction. Return on average common stock equity in 2008 and 2007 was 10.4% and 11.2%, respectively.

The Utilities Group income from continuing operations increased $12.3 million in 2008 compared to 2007. Results from the Utilities Group include the operations of the five utilities acquired in the Aquila Transaction since the July acquisition date. Earnings from continuing operations from the Electric Utilities increased $8.0 million primarily due to an increase in retail rates and increased electricity sold to retail customers.

Earnings from continuing operations from the Gas Utilities were $4.2 million for the period July 14, 2008 through December 31, 2008.

The Non-regulated Energy Group s loss from continuing operations was $23.5 million in 2008, compared to earnings of $49.5 million in 2007, primarily due to a $59.0 million after-tax ceiling test impairment at the Oil and Gas segment and lower earnings from Energy Marketing of $14.5 million. Partially offsetting these decreases was an increase in Power Generation earnings of $6.6 million, which includes the impact of increased earnings from investment partnerships and lower indirect corporate costs related to the IPP Transaction.

Consolidated revenues for 2008 were $431.0 million higher than 2007 primarily due to the addition of the utilities acquired in the Aquila Transaction and increased Oil and Gas and Coal Mining revenues, partially offset by decreased revenues from Energy Marketing.

Consolidated operating expenses for 2008 increased $500.8 million compared to 2007. Operating expenses were impacted by the $91.8 million pre-tax ceiling test impairment at the Oil and Gas segment, increased overburden removal costs at the coal mine, additional operating costs from the Wygen II plant placed into service in January, 2008 and the addition of operating costs of the acquired utilities since their acquisition date.

Income from continuing operations was also impacted by a $94.4 million pre-tax mark-to-market loss related to interest rate swaps no longer designated as hedges for accounting purposes.

2007 Compared to 2006

Consolidated income from continuing operations for 2007 was $75.3 million, compared to $55.3 million in 2006, or $2.01 per share in 2007, compared to $1.65 per share in 2006. Income from discontinued operations was $23.5 million, or $0.63 per share, compared to income of $25.8 million, or $0.77 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% and 10.6%, respectively.

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

The Non-regulated Energy Group s income from continuing operations increased $12.9 million in 2007, compared to 2006, primarily due to increased earnings from Energy Marketing of $16.9 million. This increase was partially offset by lower Power Generation earnings of $4.6 million primarily due to impairment charges and lower earnings from equity investments in 2007.

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 $32.3 million higher than 2006 due to increased revenues from the Oil and Gas, Coal Mining and Energy Marketing segments, partially offset by the Electric Utilities which had lower revenues primarily due to lower PCA and GCA pass-through cost recovery rate adjustments.

Consolidated operating expenses for 2007 increased $8.7 million compared to 2006. Increased operating expenses reflect increased compensation costs at the Energy Marketing segment, a $4.3 million increase in depreciation, depletion and amortization expense, primarily due to increased depletion at the Oil and Gas segment, and a $6.0 million increase in operations and maintenance expense. The increased expenses were partially offset by a $30.6 million decrease in fuel and purchased power primarily due to cost recovery adjustments.

Income from continuing operations was also impacted by a $4.8 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.

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, 2008, 2007 and 2006 information has been revised to remove information related to operations that were discontinued.

Utilities

Electric Utilities

	2008	2007	2006
	(in thousands)		
Revenue electric	$ 425,123	$ 270,943	$ 275,329
Revenue gas	48,296	32,468	50,026
Total revenue	473,419	303,411	325,355
Fuel and purchased power electric	222,826	133,289	146,180
Purchased gas	33,735	22,649	39,957
Total fuel and purchased power	256,561	155,938	186,137
Gross margin electric	202,297	137,654	129,149
Gross margin gas	14,561	9,819	10,069
Total gross margin	216,858	147,473	139,218
Operating expenses	138,992	94,161	93,262
Operating income	$ 77,866	$ 53,312	$ 45,956
Income from continuing operations and net income	$ 39,674	$ 31,633	$ 24,188

	2008	2007	2006
Regulated power plant fleet availability:			
Coal-fired plants	93.7%	95.4%	93.5%
Other plants	91.4%	99.4%	98.6%
Total availability	92.8%	97.2%	95.7%

2008 Compared to 2007

2008 results include the operations of Colorado Electric, which was acquired on July 14, 2008.

Income from continuing operations increased 25% primarily due to:

An increase in earnings of approximately $8.0 million primarily due to the impact of a rate increase at Cheyenne Light effective January 1, 2008; and

A 34% increase in electric MWh sales to retail customers, primarily due to the acquisition of Colorado Electric.

Partially offsetting the increase to earnings was the following:

Increased plant maintenance costs and depreciation expense of approximately $11.1 million associated with the Wygen II plant placed into service January 1, 2008; and

Lower AFUDC compared to 2007.

2007 Compared to 2006

Income from continuing operations increased 31% primarily due to the following:

Purchased power costs decreased 13% due to an 8% decrease in electricity purchased at a lower average price;

Margins from wholesale off-system sales increased 7%;

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

Lower property tax due to lower assessed property valuations.

Partially offsetting the increases to earnings were the following:

Revenues decreased 7% primarily due to a 17% decrease in wholesale off-system sales and the effects of fluctuations in cost of electricity and gas that flow through to revenues through cost recovery rate adjustments, partially offset by increased rates that went into effect January 1, 2007; and

A $4.8 million increase in interest expense due to increased borrowings and net of the capitalized interest component of AFUDC.

Gas Utilities

Operating results for the Gas Utilities are as follows:

		For the Period July 14, 2008 to December 31, 2008 (in thousands)
Revenue:		
Natural gas regulated	$	261,887
Other non-regulated		15,189
Total sales	$	277,076
Cost of sales:		
Natural gas regulated		180,556
Other non-regulated		11,294
Total cost of sales		191,850
Gross margin		85,226
Operating expenses		70,338
Operating income	$	14,888
Income from continuing operations and net income	$	4,230

As part of the Aquila Transaction, we acquired Gas Utilities in Colorado, Nebraska, Iowa and Kansas. Natural gas demand is typically higher in the first and fourth quarters as it is typically used for residential and commercial heating.

The Gas Utilities have GCAs that allow them to pass through the cost of gas to customers. For this reason, we believe gross margins are a more useful performance measure than revenues as fluctuations in the cost of gas are passed through to revenues.

In June 2008, Iowa Gas filed for a $13.6 million rate increase. Interim rates were implemented on June 13, 2008. The IUB issued an order extending the time limit for consideration of the general rate increase and has until July 2, 2009 to issue a decision on our rate request. If interim rates exceed final approved rate, the difference plus interest will be refunded or credited to customers.

In June 2008, Colorado Gas filed for a $2.8 million rate increase. On February 4, 2009, a settlement of the rate case for $1.4 million was presented to an administrative law judge. The administrative law judge will make a recommendation regarding the settlement to the CPUC. The CPUC has until June 16, 2009 to issue a decision on our rate request. Other non-regulated is related to services provided to our customers.

Non-regulated Energy Group

Oil and Gas

Oil and Gas operating results were as follows:

	2008 (in thousands)	2007	2006
Revenue	$ 106,347	$ 101,522	$ 95,078
Operating expenses*	177,535	76,085	68,990
Operating (loss) income	$ (71,188)	$ 25,437	$ 26,088
Income (loss) from continuing operations	$ (49,668)	$ 12,706	$ 12,736

* 2008 operating expenses included a $91.8 million pre-tax ceiling test impairment charge.

The following tables provide certain operating statistics for the Oil and Gas segment;

	Crude Oil and Natural Gas Production		
	2008	2007	2006
Bbls of oil sold	387,400	409,040	401,440
Mcf of natural gas sold	11,209,600	12,172,400	12,005,600
Mcf equivalent sales	13,534,000	14,626,640	14,414,240

	Average Price Received*		
	2008	2007	2006
Gas/Mcf**	$ 6.24	$ 6.19	$ 6.11
Oil/Bbl	$ 79.35	$ 60.29	$ 50.75

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

	2008	2007	2006
Average production cost (per Mcfe):			
LOE	$ 1.33	$ 0.98	$ 1.01
Production and other taxes	0.91	0.70	0.67
Total	$ 2.24	$ 1.68	$ 1.68

Depletion

	2008	2007	2006
Depletion expense/Mcfe*	$ 2.68	$ 2.21	$ 1.94

* The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. The 2008 rate was particularly impacted by product price volatility and significantly lower year-end market prices, which resulted in lower oil and gas reserve quantities.

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

	2008			2007			2006		
	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total	LOE	Gathering Compression and Processing	Total
New Mexico	$ 1.48	$ 0.29	$ 1.77	$ 1.04	$ 0.31	$ 1.35	$ 1.11	$ 0.27	$ 1.38
Colorado	1.29	0.77	2.06	0.95	0.79	1.74	1.25	0.49	1.74
Wyoming	1.55		1.55	1.19		1.19	1.15		1.15
All other properties	0.89	0.12	1.01	0.71	0.17	0.88	0.73	0.15	0.88
Total	$ 1.33	$ 0.22	$ 1.55	$ 0.98	$ 0.23	$ 1.21	$ 1.01	$ 0.18	$ 1.19

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:

	2008	2007	2006
Bbls of oil (in thousands)	5,185	5,807	5,723
MMcf of natural gas	154,432	172,964	164,754
Total MMcfe	185,542	207,806	199,092

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by Cawley, Gillespie & Associates, Inc. in 2008 and 2007, and Ralph E. Davis Associates, Inc. in 2006. 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 2008 production of approximately 13.0 Bcfe, additions from extensions, discoveries and acquisitions of 10.0 Bcfe and negative revisions to previous estimates of 19.0 Bcfe, including approximately 15.0 Bcfe due to lower product prices and higher costs.

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

	2008		2007		2006	
	Oil	Gas	Oil	Gas	Oil	Gas
Year-end prices (NYMEX)	$ 44.60	$ 5.71	$ 95.98	$ 6.80	$ 61.05	$ 5.52
Year-end prices (average well-head)	$ 32.74	$ 4.44	$ 83.23	$ 5.88	$ 52.06	$ 5.34

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2008 Compared to 2007

Loss from continuing operations was $49.7 million compared to income of $12.7 million in the prior year, primarily due to the following.

A $59.0 million after-tax non-cash ceiling test impairment charge was taken during the fourth quarter 2008. The write-down in value of our natural gas and crude oil properties resulted from low year-end prices for the commodities. The write-down of gas and oil properties was based on year end NYMEX prices of $5.71 per Mcf, adjusted to $4.44 per Mcf at the wellhead, for natural gas and $44.60 per barrel, adjusted to $32.74 per barrel at the wellhead, for crude oil;

LOE increased $3.6 million due to costs related to severe weather conditions in New Mexico, increased fuel costs and higher industry-related costs; and

Increased depletion expense of $3.7 million primarily due to negative reserve revisions driven by the impact of lower year-end commodity prices.

Partially offsetting these decreases were the following:

Increased revenues of $4.8 million primarily due to a 32% increase in the annual average hedged price of oil received and a 1% increase in the annual average hedged price of gas received, partially offset by a 7% decrease in production and the impact of a royalty settlement with the Jicarilla Apache Nation. The decrease in production resulted from severe weather at the beginning of 2008, federal drilling permit delays, voluntary shut-in of volumes in response to low price levels at the CIG pricing location and delays in drilling activity on our non-operated property as well as a reduction in capital spending due to the low commodity prices.

In 2008, we acquired additional non-operated interest in a Wyoming field in which we already held non-operated interests. The additional interest added approximately 4 Bcfe of proved reserves and is viewed as a long-term production field with increased density and up-hole re-completion potential.

2007 Compared to 2006

Income from continuing operations was comparable to the prior year.

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

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

General and administrative costs increased 15% 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% 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% due to carrying a full year of Piceance Basin acquisition debt and increased borrowings to fund drilling and exploration activity.

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:

	2008 (in thousands)	2007	2006
Revenue	$ 38,181	$ 38,658	$ 40,688
Operating expenses	23,966	36,062	32,407
Operating income	$ 14,215	$ 2,596	$ 8,281
Income (loss) from continuing operations	$ 3,121	$ (3,471)	$ 1,117

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

	2008	2007	2006
Independent power capacity:			
MW of independent power capacity in service	141	158	164
Contracted fleet plant availability:			
Gas-fired plants	96.2%	96.2%	94.7%
Coal-fired plants	95.3%	70.3%	95.7%
Total	95.9%	86.0%	95.3%

2008 Compared to 2007

Earnings from continuing operations increased $6.6 million primarily due to:

Increased earnings from our investment partnerships due to 2007 partnership impairment charges of $2.1 million after-tax for the Glenns Ferry and Rupert power plants, in which we hold a 50% ownership interest;

Increased operating income from our Gillette CT of $1.0 million after-tax. Operating income was impacted by lower gas and purchased power costs and maintenance expense;

Allocated indirect corporate costs, related to the IPP assets sold and not reclassified to discontinued operations, decreased $1.9 million after-tax. 2008 costs represent a partial year through the sale date of the IPP Transaction, compared to a full 12 months of costs in 2007; and

The recording of an impairment loss, and related costs, in 2007 of $1.8 million after-tax relating to the Ontario plant.

Partially offsetting the increased earnings was a decrease in non-operating income of $6.4 million after-tax, resulting from a change in business segment debt to equity capital structure.

2007 Compared to 2006

Income from continuing operations decreased $4.6 million primarily due to the following:

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 charges for the Glenns Ferry and Rupert power plants, in which we hold a 50% interest.

Coal Mining

Coal Mining results were as follows:

	2008 (in thousands)	2007	2006
Revenue	$ 56,901	$ 42,488	$ 36,282
Operating expenses	52,608	36,311	29,366
Operating income	$ 4,293	$ 6,177	$ 6,916
Income from continuing operations	$ 4,033	$ 6,107	$ 5,877

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

	2008 (in thousands)	2007	2006
Tons of coal sold	6,017	5,049	4,717
Cubic yards of overburden moved	12,203	7,467	6,295
Coal reserves	274,000	280,000	285,000

2008 Compared to 2007

Income from continuing operations decreased $2.1 million, or 34%, due to the following:

Increased overburden removal costs of $5.3 million due to a 63% increase in overburden yards moved, compounded by a higher strip ratio, longer haul distances and higher diesel fuel costs; and

Increased depreciation expense of $4.4 million due to an increase in the asset base and usage related to increased production.

Offsetting the decreases was a $14.4 million increase in revenues due to a 19% increase in coal sold at a higher average price. The increase in coal volumes was due to additional Wygen II and train load-out sales.

2007 Compared to 2006

Income from continuing operations increased 4% due to a 17% 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% 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.

Energy Marketing

Our Energy Marketing segment produced the following results:

	2008	2007	2006
	(in thousands)		
Revenue -			
Realized gas marketing gross margin	$ 18,593	$ 84,823	$ 54,088
Unrealized gas marketing gross margin	33,247	468	(6,546)
Realized oil marketing gross margin	1,038	4,146	2,847
Unrealized oil marketing gross margin	6,432	4,399	842
	59,310	93,836	51,231
Operating expenses	29,175	42,067	27,223
Operating income	$ 30,135	$ 51,769	$ 24,008
Income from continuing operations	$ 19,689	$ 34,178	$ 17,322

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

	2008	2007	2006
Natural gas average daily physical sales MMBtu	1,873,400	1,743,500	1,598,200
Crude oil average daily physical sales Bbls	7,880	8,600	8,800

2008 Compared to 2007

Income from continuing operations decreased $14.5 million due to the following:

A $69.3 million pre-tax decrease in realized marketing margins, primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies; and

Lower crude oil marketing margins are due to the impact of decreasing commodity prices on inventory held to meet pipeline requirements.

Partially offsetting the decrease was the following:

A $34.8 million pre-tax increase in unrealized marketing margins. Unrealized mark-to-market gains in 2008 were driven by accelerated margins within our proprietary trading portfolio and narrowing basis differentials at year end, resulting in mark-to-market gains on our hedged transportation positions. These positions are scheduled to settle and the margins realized primarily in 2009 and to a lesser extent 2010; and

Lower operating expenses as incentive compensation decreased compared to incentive compensation for strong marketing performance in 2007.

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%;

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.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with GAAP. 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. Actual results may differ from our estimates.

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.

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. The determination of future cash flows, and, if required, fair value of a long-lived asset is by it nature a highly subjective judgment. Significant judgment assumptions are required in the forecast of future operating results used in the preparation of the long-term estimated cash flows. Changes in these estimates could have a material effect on the evaluation of our long-lived assets.

According to SFAS 142, goodwill and other intangibles are required to be evaluated whenever indicators of impairment exist and at least annually. We conduct our annual evaluations during the fourth quarter. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount. The second step, if necessary, measures the amount of the impairment. The underlying assumptions used for determining fair value are susceptible to change from period to period and could potentially cause a material impact to the income statement. Management s assumptions about future revenues and operating costs, the amount and timing of anticipated capital expenditures for power generating facilities at our utility operations, discount rates, inflation rates, and economic conditions, require significant judgment. The 2008 Aquila Transaction resulted in a significant increase in our goodwill balance. As of December 31, 2008, our total goodwill relating to the Aquila Transaction was $344.5 million.

Regulatory Accounting

We account for certain regulated operations under the provisions of SFAS 71. As a result, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probably of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders to other regulatory entities, and the status of any pending or potential deregulation issues. These assessments reflect the current political and regulatory climate at the state and federal levels, and are subject to change in the future.

Unbilled Utility Revenues

Sales related to the delivery of energy are generally recorded when services or energy is delivered to customers. However, the determination of sales is based on reading customers meters, which occurs systematically throughout the month. At the end of each month, an estimate is made of the amount of energy delivered to customers after the date of the last meter reading. The unbilled revenue is calculated each month based on estimated customer usage, weather factors, line losses, and applicable customer rates. Total unbilled revenues at December 31, 2008 were $73.0 million.

Full Cost Method of Accounting for Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available successful efforts and full cost. 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 spot 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. Our net capitalized costs were more than the full cost ceiling at December 31, 2008 requiring an after tax write-down of $59.0 million. Given the fluctuations in natural gas and oil prices, we can provide no assurance that future write-downs will not occur depending on oil and gas prices at that point in time. On December 31, 2008, the SEC issued final rules amending its oil and gas reporting requirements effective January 1, 2010. The final rule changes the use of prices at the end of each reporting period to an average of the first day of the month price for the preceding twelve months. The SEC has proposed to apply these rules to the Annual Reports on Form 10-K for the period ending December 31, 2009, however there is the possibility of delaying the compliance date until the FASB has issued final accounting standards in line with the SEC rules.

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. An independent petroleum engineering company prepares reports that estimate our proved oil and natural gas reserves annually. 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 estimating our oil and natural gas reserves, the estimates 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 unit-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.

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Risk Management Activities

In addition to the information provided below, see Note 2 Risk Management Activities, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges under SFAS 133 are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or fair values. The effective portion of changes in fair values of derivatives designated as cash flow hedges is recorded as a component of other comprehensive income (loss) until it is reclassified into earnings in the same period that the hedged item is recognized in earnings. The ineffective portion of changes in fair value of derivatives designated as cash flow hedges is recorded in current earnings. Changes in fair value of derivatives designated as fair value hedges are recognized in current earnings along with fair value changes of the underlying hedged item.

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 to fix the price received for anticipated future production at our Oil and Gas segment, or to fulfill the annual winter hedging plan for our gas utilities (see below), 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 Energy Marketing 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.

As allowed by state regulatory commissions, we have entered into certain financial instruments to reduce our customers underlying exposure to fluctuations in gas prices. These financial instruments are considered derivatives under SFAS 133 and are marked-to-market. We apply the provisions of SFAS 71 to periodic changes in fair value of the derivatives associated with these instruments and record an offset in regulatory asset or regulatory liability accounts. Most of our contracts for purchase and sale of natural gas qualify for the normal purchase and normal sale exceptions under SFAS 133, and are not required to be recorded as derivative assets and liabilities.

Counterparty Credit Risk and Allowance for Doubtful Accounts

Our largest counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and collateral requirements under certain circumstances, including the use of master netting agreements in our natural gas marketing segment.

We continuously monitor collections and payments from our customers and establish an allowance for doubtful accounts based upon our historical experience and any specific customer collection issue that we have identified. The allowances provided are estimated and may be impacted by economic, market and regulatory conditions, which could have an effect on future allowance requirements and significantly impact future results of operations. 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 Company, as described in Note 17 to the Consolidated Financial Statements in this Annual Report on Form 10-K, has three defined benefit pension plans and three defined benefit post-retirement healthcare plans. Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; rate of future increases in compensation levels; and healthcare cost projections. 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. Through 2007, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a September 30 measurement date. Effective in 2008, we changed our measurement date to December 31. 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.

The pension benefit cost for 2009 for our non-contributory funded pension plan is expected to be $11.8 million compared to $1.8 million in 2008. The estimated discount rate used to determine annual benefit cost accruals will be 6.20% in 2009; the discount rate used in 2008 was 6.35%. In selecting the discount rate, we consider cash flow durations for each Plan's liabilities and returns on high credit quality fixed income yield curves for comparable durations.

Our pension plan assets are held in trust and primarily consist of equity, fixed income and real estate securities. In 2008, our target long-term investment allocations were 75% equity and 25% fixed income. As a result of the severe decline in equity values in the fourth quarter of 2008 and in light of the improved relative value of fixed income investment opportunities, we are undergoing a review to consider a revision of the pension plan investment allocations.

The revision is expected to result in a higher fixed income allocation. Until the investment allocation review is completed and implemented, we have suspended our practice of rebalancing the portfolio on a quarterly basis. This has resulted in an investment allocation of 60% equities, 35% fixed income/cash and 5% real estate at December 31, 2008.

As of December 31, 2008, our average assumed discount rate was 6.2% and our average expected return on plan assets was 8.5%. We do not pre-fund our non-qualified pension plans or two of the three postretirement benefit plans. The table below shows the expected impacts of a 1% increase or decrease to our 6.2% discount rate assumption:

Change in Assumed Discount Rate	Impact on December 31, 2008 Accumulated Postretirement Benefit Obligation (in thousands)		Impact on 2008 Service and Interest Cost	
Increase 1%	$	3,445	$	325
Decrease 1%	$	(2,552)	$	(251)

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. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of the current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

Liquidity and Capital Resources

Overview

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

Financial Position Summary (in thousands)	2008	2007	Percentage Change
Cash and cash equivalents	$ 168,491	$ 76,889	119.1%
Short-term debt	705,878	167,326	321.9%
Long-term debt	501,252	503,301	(0.4)%
Stockholders equity	1,050,536	969,855	8.3%
Ratios			
Long-term debt ratio	32.3%	34.2%	(5.5)%
Total debt ratio	53.5%	40.9%	30.8%

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt financings, taken as a whole, provide sufficient resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures during the next 12 months, however, a material change in available financing (including further changes resulting from the ongoing financial crisis) could impact our ability to fund our current liquidity and capital resource requirements.

Liquidity

Historically, our principal sources of short-term liquidity have been our revolving credit facilities and cash from operations. We have utilized availability under our revolving credit facilities to manage our cash flows, principally due to the seasonality of our utility businesses and changes in the trading volumes of our energy marketing operation. Our principal sources of long-term liquidity have been proceeds raised from public and private offerings of equity and long-term debt securities issued by the Company and its subsidiaries. We have also managed liquidity needs through hedging activities, primarily in connection with seasonal needs of our Utility operations (including seasonal peaks in fuel requirements), interest rate movements, and commodity price movements. As a result of the recent turmoil in the capital and credit markets, we expect to improve our liquidity profile by deferring or curtailing discretionary capital expenditures and operate certain of our businesses in a manner that conserves cash.

At December 31, 2008, we had approximately $168.5 million of unrestricted cash on hand, and had $508.2 million of cash borrowings and letters of credit outstanding under our credit facilities, as set forth below.

Credit Facility	Expiration	Maximum Capacity (in millions)	Borrowings and Letters of Credit Issued at December 31, 2008
Unsecured Revolving Credit Facility	May 4, 2010	$ 525.00	$ 381.7

Enserco Facility	May 8, 2009	$ 300.00	$ 126.5

Credit Facilities

Corporate Credit Facility

In July 2008, our unsecured revolving credit facility was increased from $400 million to $525 million. The cost of borrowing or letters of credit under our corporate revolver is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 1.14% one-month borrowing rate as of December 31, 2008). The revolver can be used to fund our working capital needs and for general corporate purposes. At December 31, 2008, we had borrowings of $321.0 million and $60.7 million of letters of credit issued under the facility, and we had approximately $143.3 million of capacity available for additional borrowings or letters of credit.

Our revolving credit facility contains 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: (i) a consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income beginning January 1, 2005; (ii) a recourse leverage ratio not to exceed 0.70 to 1.00 for the first year after the Aquila Transaction and, thereafter, a ratio not to exceed 0.65 to 1.00; and, (iii) an interest expense coverage ratio of not less than 2.5 to 1.0. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding.

At December 31, 2008, our consolidated net worth was $1,050.5 million, which was approximately $266.4 million in excess of the net worth we were required to maintain under the credit facility. At December 31, 2008, our long-term debt ratio was 32.3%, our total debt leverage (long-term debt and short-term debt) was 53.5%, our recourse leverage ratio was approximately 56.3% and our interest expense coverage ratio for the twelve month period ended December 31, 2008 was 3.89 to 1.0. Accordingly, we were in compliance with all of our financial covenants in the revolving credit facility as of December 31, 2008.

In addition to covenant violations, an event of default under the credit facility may be triggered by other events, such as 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. Subject to applicable cure periods (none of which apply to a failure to timely pay indebtedness), an event of default would permit the lenders to restrict our ability to further access the credit facility for loans or new letters of credit, and could require both the immediate repayment of any principal and interest outstanding and the cash collateralization of outstanding letter of credit obligations.

The credit facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after giving effect to such action.

Enserco Facility

Our Energy Marketing subsidiary, Enserco, has a $300 million uncommitted, discretionary line of credit to provide support for the purchase, sale, transportation and storage of natural gas and crude oil. The line of credit is secured by Enserco s assets, and it expires on May 8, 2009The Enserco credit facility allows for the issuance of letters of credit and loans for our marketing operations. The cost of letters of credit issued under the facility is determined by the type of transaction the letter of credit is securing and ranges from an annualized cost of 100 basis points to 150 basis points. We have not historically used the facility for loans. Outstanding borrowings accrue interest at the higher of: 50 basis points above the Federal Funds Rate (0.75% at December 31, 2008) or 100 basis points above prime (4.25% at December 31, 2008). The maximum aggregate amount of such letters of credit and loans issued under the facility is subject to a borrowing base sublimit. The sublimit is determined based on the net working capital and tangible net worth of Enserco. Loans under the facility are subject to a maximum sublimit of $100 million. At December 31, 2008, $126.5 million of letters of credit were issued under the facility and there were no cash borrowings outstanding.

Acquisition Facility

In July 2008, in conjunction with the closing of the Aquila Transaction, we borrowed $382.8 million under our $1 billion bridge acquisition credit facility dated May 7, 2007. The Acquisition Facility was structured as a single-draw term loan facility for the sole purpose of financing the Aquila Transaction and following our July 2008 borrowing we have no additional borrowing capacity available under the facility.

Borrowings under the term loan are available 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 was originally 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 loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to provide as follows:

The maturity date was extended from February 5, 2009 to December 29, 2009;

The applicable margin for base-rate borrowings was increased to (i) 200 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 250 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 300 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 350 basis points thereafter. If our credit ratings, as assigned by S&P and Moody s, fall below investment grade credit ratings, the applicable margin will increase by an additional 25 basis points; and

Increased the applicable margin for LIBOR borrowings to (i) 300 basis points for the period commencing December 18, 2008 through March 31, 2009, (ii) 350 basis points for the period commencing April 1, 2009 through June 30, 2009, (iii) 400 basis points for the period commencing July 1, 2009 through September 30, 2009, and (iv) 450 basis points thereafter. If our credit ratings, as assigned by S&P and Moody s, fall below investment grade credit ratings and the applicable margin will increase by 25 basis points.

In connection with the amendment, we also received the consents necessary to replace the administrative agent (ABN AMRO Bank) and appointed The Royal Bank of Scotland PLC as successor agent.

As of December 31, 2008, the facility has a borrowing spread of 300 basis points over LIBOR (which equates to a 3.44% one-month borrowing rate as of December 31, 2008).

The Acquisition Facility also includes certain affirmative and negative covenants and events of default that largely replicate the covenants in our corporate revolving credit facility. We were in compliance with all such covenants as of December 31, 2008.

Cross-Default Provisions

Our revolving credit facility and acquisition term loan facility contain cross-default provisions that would result in an event of default under the credit facility upon (i) a failure by us or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) to timely pay indebtedness in an aggregate principal amount of $20 million or more, or (ii) the occurrence of a default under any agreement under which we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) may incur indebtedness in an aggregate principal amount of $20 million or more, and such default continues for a period of time sufficient to permit an acceleration of the maturity of such indebtedness or a mandatory prepayment of such indebtedness. In addition, each of our credit facilities contains default provisions under which an event of default would result if we or certain of our subsidiaries (including, among others, Enserco and most of our Utility subsidiaries) fail to timely make certain payments, such as ERISA funding obligations or payments in satisfaction of judgments, in an aggregate principal amount of $20 million or more.

Working Capital

The most significant activities impacting working capital are our capital expenditures and the purchase of natural gas for our Gas Utilities. We could experience significant working capital requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices. We anticipate using the combination of credit capacity available under our corporate revolver and cash on hand to meet our peak winter working capital requirements.

Collateral

As of December 31, 2008, we had posted with counterparties the following amounts (in thousands) of collateral (in the form of cash or letters of credit):

Trading positions (energy marketing)	$	110,205
Utility cash collateral requirements		8,744
Total Funds on Deposit	$	118,949

Collateral requirements for our trading positions will fluctuate based on the movement in commodity prices and our credit rating. Changes in collateral requirements will vary depending on the magnitude of the price movement and the current position of our energy marketing trading portfolio. As these trading positions settle in the future, the collateral will be returned.

We are required to post collateral with certain commodity and pipeline transportation vendors. This amount will fluctuate depending on gas prices and projected volumetric deliveries.

Debt Retirement Transactions

In 2006, we entered into a credit agreement under which floating-rate debt was issued to finance the Wygen I project. The project debt matured in June 2008. We retired the $128.3 million of project debt with cash borrowed under our revolving credit facility. See Off-Balance Sheet

Arrangements Variable Interest Entities below for additional information.

In conjunction with the completion of the IPP Transaction, $67.5 million of project debt relating to certain Colorado IPP facilities was retired in July 2008. We used proceeds from the IPP Transaction to retire this debt.

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Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates. While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, 2008, internal borrowings outstanding within our utility money pool included (in thousands):

Utility Subsidiary	Borrowings Outstanding at December 31, 2008
Black Hills Utility Holdings	$ 61,432
Black Hills Power	67,920
Cheyenne Light	3,982

Registration Statements

Our articles of incorporation authorize the issuance of 100 million shares of common stock, $1 par value, and 25 million shares of preferred stock, no-par value. As of December 31, 2008, we had approximately 38.6 million shares of common stock outstanding, and no shares of preferred stock outstanding. The Company has an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our finance arrangements and restrictions imposed by federal and state regulatory authorities. As of December 31, 2008, we had not issued any securities under this shelf registration statement.

Anticipated Financing Plans

Enserco Facility

We are currently pursuing a renewal of the $300 million Enserco Facility with our existing lenders and other banks prior to its May 8, 2009 expiration. We also intend to change the facility to a committed facility upon its renewal.

Because of the uncommitted nature of the existing Enserco Facility, and given the current condition of the credit markets, we are conducting our Enserco business operations in a manner to preserve liquidity, which includes minimizing our utilization of the facility.

The Enserco Facility may be impacted by the current global credit crisis. The credit crisis is prompting most commercial banks to reduce their commitments or deleverage their portfolios. Consequently, some of the participating banks in the Enserco Facility may decline to participate in new credit transactions going forward. If a bank declined to participate in the facility, the existing issued letters of credit would remain in place; however, the remaining capacity available would be reduced by that bank s pro rata participation under the facility for future transactions.

The two largest participating banks under the Enserco Facility are Fortis Capital Corp. and BNP Paribas, which have participation levels of $105 million and $75 million, respectively. In October 2008, BNP Paribas announced that it had agreed to acquire Fortis operations in Belgium and Luxembourg and its international banking franchises, including Fortis Capital Corp. In February 2009, the Fortis shareholders voted down the proposed transaction. Consequently, we cannot predict whether the two entities will continue to participate in the Enserco Facility at their current levels, regardless of whether or not a potential transaction is completed.

Factors Influencing Liquidity

Due to recent market conditions and the decline in the fair value of our pension plan assets, the funding status of our pension plan in 2009 is likely to deteriorate as compared to 2008. The final determination of pension plan contributions for 2009 and future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of the pension assets and changes in actuarial assumptions (in particular, the discount rate used in determining the projected benefit obligation). As a result, we may be required to contribute material amounts to our pension plans in 2009 and future periods, which could materially affect our liquidity and results of operations.

Many of our operations are subject to seasonal fluctuations in cash flow. We have traditionally sourced (i) variations in the working capital needs of our subsidiaries with cash on hand and capacity available under our credit facilities, and (ii) the capital expenditures of our subsidiaries through a combination of internally generated cash and equity contributions to our subsidiaries from us (financed primarily with net proceeds of equity and long-term debt issuances by us) and, in limited instances, debt offerings by our subsidiaries. Increased volatility in commodity prices and interest rates, magnified by the recent turmoil in the bank and capital markets, has made it more difficult for us to adequately forecast the liquidity needs of our subsidiary operations and our ability to raise capital for our subsidiaries on reasonable terms. Moreover, based on general market conditions and various predictions of a prolonged recession, we face an increasing risk of higher payment defaults by our customers. As a result, our liquidity needs are subject to greater fluctuation and are more difficult to forecast than in the past.

To the extent we issue long-term debt securities or arrange new credit facilities or extensions of existing credit lines in the bank loan market, we expect to pay significant fees in connection with these activities. In particular, future banking fees for new credit facilities or additional maturity extensions may be significantly more costly.

Although our Utility operations are subject to regulatory lag in terms of recovering capital expenditures and other prudently-incurred costs, revenues from our Utility operations traditionally have been stable. In light of volatile commodity prices and the potential of a severe economic recession, our cash flows from Utility operations could be less stable going forward.

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located.

As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary s liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders.

Credit Ratings

Credit ratings impact our ability to obtain short- and long-term financing, the cost of such financing, and vendor payment terms, including collateral requirements. As of December 31, 2008, our senior unsecured credit ratings, as assessed by the three major credit rating agencies, were as follows:

Rating Agency	Rating	Outlook
Moody s	Baa3	Stable
S&P	BBB-	Stable
Fitch	BBB	Stable

In addition, the first mortgage bonds issued by Black Hills Power were rated at December 31, 2008 as follows:

Rating Agency	**Rating**	**Outlook**
Moody s	Baa1	Stable
S&P	BBB	Stable
Fitch	A-	Stable

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events. If our senior unsecured credit rating should drop below investment grade, pricing under our credit agreements would be affected, increasing annual interest expense (pre-tax) by approximately $2.6 million based on our December 31, 2008 debt balances.

We have an interest rate swap with a notional amount of $50.0 million which has collateral requirements based upon our corporate credit ratings. At our current credit ratings, we would be required to post collateral for any amount by which the swap s negative mark-to-market fair value exceeds $(20.0) million. If our senior unsecured credit rating would drop to BB+ or below by S&P, or Ba1 or below by Moody s, we would be required to post collateral for the entire amount of the swap s negative market-to-market fair value.

Capital Requirements

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

	2008	2007	2006
	(in thousands)		
Acquisition costs:			
Payment for acquisition of net assets,			
net of cash acquired	$ 938,423(1)	$	$
Property additions:			
Utilities			
Electric Utilities	186,237(2)	104,963	132,340
Gas Utilities	19,337(3)		
Non-regulated Energy			
Oil and Gas	89,169(3)	72,153	158,846(3)
Power Generation	5,105	128	1,142
Coal Mining	25,190	4,991	5,807
Energy Marketing	22	177	928
Corporate	11,033	22,316(4)	1,972
	336,093	204,728	301,035
Discontinued operations investing activities	29,836(5)	62,319(5)	7,415
	1,304,352	267,047	308,450
Common stock dividends	53,663	50,300	43,960
Maturities/redemptions of long-term debt	130,297	62,109	36,518
Discontinued operations financing activities	73,928	12,858	32,753
	$ 1,562,240	$ 392,314	$ 421,681

(1) Cash paid for the Aquila properties, net of cash acquired.

(2) Includes $99.3 million for Wygen III construction.
(3) Includes $16.9 million for acquisition of a non-operated interest in Wyoming in 2008 and $75.4 million in 2006 for acquisitions in the Piceance Basin in Colorado.
(4) Includes $19.1 million for Aquila acquisition and development costs.
(5) Includes $27.8 million and $62.2 million in 2008 and 2007, respectively, for the construction of the Valencia plant, which was sold in the IPP Transaction.

Our capital additions for 2008 were $365.9 million, exclusive of the $938.4 million payment for the Aquila Transaction. Capital expenditures were primarily for construction of the Wygen III power plant, acquisition of non-operated oil and gas interests in Wyoming, development drilling of oil and gas properties, increased coal mining equipment and maintenance capital.

Our capital additions for 2007 were $267.0 million. Capital expenditures were primarily for the construction of the Wygen II power plant, the Valencia power plant, which is reclassified to Discontinued operations, development drilling of oil and gas properties, capitalized costs associated with the Aquila Transaction, and maintenance capital.

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

Forecasted Capital Expenditures

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

	2009 (in thousands)	2010	2011
Utilities:			
Electric Utilities[(1)(2)(3)]	$ 178,280	$ 107,900	$ 95,960
Gas Utilities	42,510	46,000	49,700
Non-regulated Energy:			
Oil and Gas[(4)]	38,620	40,020	35,770
Power Generation	3,930	1,710	1,460
Coal Mining	6,590	11,810	8,950
Energy Marketing	4,140	20	14
Corporate	13,340	7,510	6,230
	$ 287,410	$ 214,970	$ 198,084

(1) Electric Utilities capital requirements include approximately $61.5 million and $16.3 million for the development of the Wygen III coal-fired plant in 2009 and 2010, respectively. Forecasted expenditures assume we retain a 75% ownership interest in the plant.
(2) Electric Utilities capital requirements include approximately $17.9 million for Wygen III-related transmission projects in 2009.
(3) Capital expenditures for our Electric Utilities do not include any expenditures associated with our pending Colorado Electric Energy Resource Plan. This plan proposes construction of up to five gas generating plants to serve the Colorado Electric customers.
(4) Development capital for our oil and gas properties is expected to be limited to no more than the cash flows produced by those properties. Continued low commodity prices make many of our development drilling sites uneconomical, which could further reduce our development capital expenditures.

Contractual Obligations and Commitments

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2008:

	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)]	$ 503,458	$ 2,078	$ 36,240	$ 235,360	$ 229,780
Unconditional purchase obligations[(c)]	1,092,241	259,671	582,157	109,437	140,976
Operating lease obligations[(d)]	10,314	3,703	4,107	1,114	1,390
Capital leases[(e)]	49	20	29		
Other long-term obligations[(f)]	40,160				40,160
Employee benefit plans[(g)]	62,836	22,785	13,671	8,870	17,510
Liability for unrecognized tax benefits in accordance with FIN 48[(h)]	59,410		32,808	12,559	14,043
Credit facilities[(i)]	703,800	703,800			
Total contractual cash obligations [(j)]	$ 2,472,268	$ 992,057	$ 669,012	$ 367,340	$ 443,859

(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: $33.8 million in 2009, $32.4 million in 2010, $31.0 million in 2011, $30.8 million in 2012 and $23.3 million in 2013. Variable rate interest using applicable rates is calculated as of December 31, 2008.
(c) Unconditional purchase obligations include the capacity costs associated with our power purchase agreement with PacifiCorp, the capacity and energy costs associated with our power purchase agreement with PSCo, 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 2008 and price assumptions using existing prices at December 31, 2008. The pricing for the PSCo power purchase agreement is based on annual contracted capacity and an 85% load factor at current FERC approved rates. Our transmission obligations are based on filed tariffs as of December 31, 2008. Actual future costs under the variable rate contracts may differ materially from the estimates used in the above table.
(d) Includes operating leases associated with several office buildings and call centers, a lease for compressor equipment and vehicle leases.
(e) Represents a capital lease on office equipment.
(f) Includes our asset retirement obligations associated with our Oil and Gas, Coal Mining and Electric and Gas Utilities segments as discussed in Note 8 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(g) Represents estimated employer contributions to employee benefit plans through the year 2018.
(h) Years 1-3 includes an estimated reversal of approximately $22.9 million of gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction.
(i) Includes $321.0 million on our corporate credit facility and $382.8 million on our Acquisition Facility.
(j) Amounts in the above table exclude any obligation that may arise from our derivatives, including interest rate swaps and commodity related contracts that have a negative fair value at December 31, 2008. These amounts have been excluded as it is impracticable to reasonably estimate the final amount and/or timing of any associated payments.

Dividends

Our dividend payout ratio for the year ended December 31, 2008, was 51% compared to 52% and 55% for the years ended December 31, 2007 and 2006, respectively. Dividends paid on our common stock totaled $1.40 per share in 2008, as compared to $1.37 per share in 2007 and $1.32 per share in 2006. Our three-year annualized dividend growth rate was 3.03%, and all dividends were paid out of operating cash flows.

In January 2009, our Board of Directors declared a quarterly dividend of $0.355 per share. If this dividend is maintained throughout 2009, it will be equivalent to $1.42 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.

Due to our holding company structure, substantially all of our operating cash flow is provided by dividends paid or distributions made by our subsidiaries. As a result, certain statutory limitations could affect dividend levels. Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in capital accounts. The cash to pay dividends to our shareholders is derived in part from dividends received from our utility subsidiaries. Our utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company.

Off-Balance Sheet Arrangements

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2008, we had guarantees totaling $83.4 million in place. Of the $83.4 million, $77.0 million was related to performance obligations under subsidiary contracts and $6.4 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 19 to Consolidated Financial Statements in this Annual Report on Form 10-K.

As of December 31, 2008, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2008	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2009
Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Indemnification for subsidiary reclamation/surety bonds	6,377	Ongoing
	$ 83,377	

Variable Interest Entities

In 2003, our Black Hills Wyoming subsidiary entered into an agreement with Wygen Funding, Limited Partnership (the variable interest entity) to lease the Wygen I plant. We were considered the primary beneficiary of this arrangement and, therefore, we included the VIE in our consolidated financial statements. The initial term of the lease was five years and included a purchase option equal to the adjusted acquisition cost, which was essentially equal to the cost of the plant. We guaranteed the obligations of Black Hills Wyoming under the lease agreement.

At the end of the initial lease term in June 2008, we elected to purchase the Wygen I plant at an adjusted acquisition cost of $133.1 million. In conjunction with this purchase, we retired $128.3 million of Wygen I project debt through borrowings on our revolving credit facility, and extinguished the $111.0 million guarantee obligation under the Wygen I lease. Since the plant and its financial activities were previously consolidated into our financial statements, the transaction had minimal impact on our consolidated financial statements.

Cash Flow Activities

2008

Cash flows from operations of $145.6 million decreased $110.6 million from the prior year amount, affected by a $127.4 million decrease in income from continuing operations and by the following:

A $98.5 million decrease in cash flows from the change in operating assets and liabilities. The primary changes include changes in working capital accounts and current tax effects of both the IPP Transaction and the Aquila Transaction.;

Higher depreciation, depletion and amortization expense of $35.5 million;

A $94.4 million pre-tax unrealized loss related to interest rate swaps marked-to-market through earnings; and

A $91.8 million pre-tax ceiling test impairment charge to write down the net carrying value of our natural gas and crude oil properties due to low year-end commodity prices.

We had cash outflows from investing activities of $457.1 million, including:

The acquisition costs of $938.4 million for the Aquila Transaction; and

Approximately $328.9 million of property, plant and equipment additions. Significant additions during 2008 included approximately $99.3 million for Wygen III, approximately $75.3 million for development drilling at our oil and gas properties, and $16.9 million for the acquisition of an additional non-operated interest in a Wyoming oil and gas property.

Partially offsetting the cash outflows from investing activities was $835.6 million of cash received for the IPP Transaction.

We had cash inflows from financing activities of $398.7 million primarily due to the following:

A $382.8 million increase in borrowings under the Acquisition Facility, in conjunction with the Aquila Transaction; and

A $284.0 million increase in borrowings on our revolving bank facility.

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

The payment of $53.7 million of cash dividends on common stock;

Repayment of $130.3 million of long-term debt, including $128.3 million for the Wygen I project level debt; and

Repayment of $73.9 million for Colorado IPP project-level debt, which was retired as part of the IPP Transaction and is included in financing activities of discontinued operations.

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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 of $256.3 million decreased $4.0 million from the prior year amount, affected by a $20.0 million increase in income from continuing operations and the following:

A $28.6 million increase in cash flows from the change in current operating assets and liabilities. This was primarily driven by decreases in cash flow resulting from changes in net accounts receivable and accounts payable, which were more than offset by $26.2 million more in cash flows due to changes in materials, supplies and fuel during the year. Fluctuations in our materials, supplies and fuel balances were largely the result of natural gas inventory held by our Energy Marketing company in the form of storage agreements;

A $32.1 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 $4.3 million; and

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.

We had cash outflows from investing activities of $264.5 million, including:

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;

Approximately $52.6 million of property, plant and equipment additions including ongoing maintenance capital in the normal course of business; and

Approximately $56.0 million for construction expenditures for the Valencia IPP plant, which is included in investing activities of discontinued operations.

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 by Cheyenne Light.

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 $35.0 million including the call of our outstanding debt with GE Capital of $23.5 million, as well as long-term debt maturities.

Market Risk Disclosures

Our activities 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 7 and 8 of our Notes to Consolidated Financial Statements; and
- Foreign currency exchange risk associated with our natural gas marketing business transacted in Canadian dollars.

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

To manage and mitigate these identified risks, we have adopted the 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.

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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 Risk Management Policies and Procedures as approved by our 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, 2008 and 2007, are set forth in Note 2 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Non Regulated Trading Activities

The following table provides a reconciliation of activity in our natural gas and crude oil marketing portfolio that has been recorded at fair value including market value adjustments on inventory positions that have been designated as part of a fair value hedge during the year ended December 31, 2008 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2007	$	3,718 [(a)]
Net cash settled during the period on positions that existed at December 31, 2007		26,410
Change in fair value due to change in assumptions		1,898
Unrealized gain on new positions entered during the period and still existing at December 31, 2008		49,541
Realized loss on positions that existed at December 31, 2007 and were settled during the period		(33,890)
Change in cash collateral[(b)]		(15,027)
Unrealized loss on positions that existed at December 31, 2007 and still exist at December 31, 2008		(4,203)
Total fair value of energy marketing positions at December 31, 2008	$	28,447 [(a)]

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(a) The fair value of energy marketing positions consists of derivative assets/liabilities held at fair value in accordance with SFAS 157 and market value adjustments to natural gas inventory that has been designated as a hedged item as part of a fair value hedge in accordance with SFAS 133, as follows (in thousands):

		December 31, 2008		December 31, 2007
Net derivative assets	$	54,117	$	14,797
Cash collateral		(16,315)		(1,287)
Market adjustment recorded in material, supplies and fuel		(9,355)		(9,792)
	$	28,447	$	3,718

(b) We adopted FSP FIN 39-1 effective January 1, 2008. See Note 2 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Therefore, the above reconciliation does not present a complete picture of our overall portfolio of trading activities or our expected cash flows from energy trading activities. In our natural gas and crude oil marketing operations, we often employ strategies that include utilizing 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 generally does not allow us to mark our inventory, transportation or storage positions to market. The result is that while a significant majority of our energy marketing positions are fully 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.

We adopted the provisions of SFAS 157 on January 1, 2008. SFAS 157 provides a single definition of fair value and establishes a fair value hierarchy which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. We use the fair value methodology outlined in SFAS 157 to value the assets and liabilities for our outstanding derivative contracts. See Note 3 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

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The sources of fair value measurements were as follows (in thousands):

Source of Fair Value	Maturities Less than 1 year	1 2 years	Total Fair Value
Level 1	$ (16,315)	$	$ (16,315)
Level 2	42,342	633	42,975
Level 3	11,142		11,142
Market value adjustment for inventory (see footnote (a) above)	(9,355)		(9,355)
Total	$ 27,814	$ 633	$ 28,447

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:

	December 31, 2008 (in thousands)	December 31, 2007
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 28,447	$ 3,718
Market value adjustments for inventory, storage and transportation positions that are not marked-to-market under GAAP	45,192	24,952
Fair value of all forward positions (non-GAAP)	73,639	28,670
Cash collateral included in GAAP marked-to-market fair value	16,315	1,287
Liquidity reserve included in GAAP marked-to-market fair value[(1)]		1,898
Fair value of all forward positions excluding cash collateral and Liquidity reserve (non-GAAP)	$ 89,954	$ 31,855

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(1) In accordance with GAAP and industry practice prior to the issuance of SFAS 157, we included a liquidity reserve in our GAAP marked-to-market fair value. This liquidity reserve accounted for the estimated impact of the bid/ask spread in a liquidation scenario under which we are forced to liquidate our forward book on the balance sheet date. As a result of our adoption of SFAS 157, the Company discontinued its use of a liquidity reserve in valuing the total forward position within its energy marketing portfolio. See Note 3 of the Consolidated Financial Statements in this Annual Report on Form 10-K.

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% of our natural gas and 100% 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 certain of our power generating activities.

The Company has entered into agreements to hedge a portion of its estimated 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	
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	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
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	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
San Juan El Paso	02/28/2008	Swap	01/10	03/10	3,000	$	8.55
San Juan El Paso	04/09/2008	Swap	04/10	06/10	5,000	$	7.26
San Juan El Paso	04/30/2008	Swap	04/10	06/10	2,500	$	7.65
AECO	08/20/2008	Swap	04/10	06/10	1,000	$	7.73
San Juan El Paso	08/20/2008	Swap	07/10	09/10	5,000	$	7.74
AECO	08/20/2008	Swap	07/10	09/10	1,000	$	7.88
AECO	10/24/2008	Swap	10/10	12/10	1,000	$	7.05
San Juan El Paso	12/19/2008	Swap	10/09	12/09	1,000	$	5.12
San Juan El Paso	12/19/2008	Swap	04/10	06/10	1,500	$	5.39
San Juan El Paso	12/19/2008	Swap	07/10	09/10	3,000	$	5.95
San Juan El Paso	12/19/2008	Swap	10/10	12/10	5,000	$	5.89
CIG	01/26/2009	Swap	04/10	06/10	2,000	$	4.45
CIG	01/26/2009	Swap	07/10	09/10	2,000	$	4.47
CIG	01/26/2009	Swap	10/10	12/10	2,000	$	4.68
CIG	01/26/2009	Swap	01/11	03/11	2,000	$	6.00
NWR	01/26/2009	Swap	01/11	03/11	2,000	$	6.05
San Juan El Paso	01/26/2009	Swap	01/11	03/11	5,000	$	6.38
San Juan El Paso	02/13/2009	Swap	01/11	03/11	2,500	$	6.16
San Juan El Paso	02/13/2009	Swap	10/10	12/10	3,000	$	5.35
NWR	02/13/2009	Swap	04/10	12/10	1,000	$	4.20

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Crude Oil

Location	Transaction Date	Hedge Type	Term		Volume (Bbls/month)	Price	
NYMEX	03/23/2007	Swap	01/09	03/09	5,000	$	67.60
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	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
NYMEX	02/28/2008	Put	01/10	03/10	5,000	$	85.00
NYMEX	04/09/2008	Swap	04/10	06/10	5,000	$	99.60
NYMEX	04/30/2008	Put	04/10	06/10	5,000	$	85.00
NYMEX	05/29/2008	Put	04/10	06/10	5,000	$	105.00
NYMEX	07/16/2008	Swap	04/10	06/10	5,000	$	135.10
NYMEX	07/16/2008	Swap	07/10	09/10	5,000	$	134.90
NYMEX	08/20/2008	Put	07/10	09/10	5,000	$	90.00
NYMEX	09/03/2008	Put	07/10	09/10	5,000	$	90.00
NYMEX	10/24/2008	Put	07/10	09/10	5,000	$	60.00
NYMEX	12/05/2008	Swap	10/10	12/10	5,000	$	65.20
NYMEX	01/26/2009	Swap	10/10	12/10	5,000	$	60.15
NYMEX	01/26/2009	Swap	01/11	03/11	5,000	$	60.90
NYMEX	02/13/2009	Swap	01/11	03/11	5,000	$	60.05

The hedge agreements entered into by the Company had a fair value of approximately $26.4 million as of December 31, 2008.

Power Generation

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, 2008, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 8 years. These swaps have been designated as hedges in accordance with SFAS 133 and accordingly their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet.

We also have interest rate swaps with a notional amount of $250.0 million which were entered into for the purpose of hedging interest rate movements that would impact long-term financings that were originally expected to occur in 2008. The swaps were originally designated as cash flow hedges in accordance with SFAS 133 and the mark-to-market value was recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheet. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined that the forecasted long-term debt financings were probable of not occurring in the time period originally specified and as a result, the swaps are no longer effective hedges in accordance with SFAS 133 and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during the fourth quarter of 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are ten and twenty year swaps which have amended mandatory early termination dates ranging from September 30, 2009 to December 29, 2009.

Further details of the swap agreements are set forth in Note 2 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2008 and 2007, our interest rate swaps and related balances were as follows (in thousands):

December 31, 2008	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
Interest rate swaps	$ 150,000	5.04%	8.00	$	$	$ 5,740	$ 22,495	$ (28,235)	$
Interest rate swaps	$ 250,000	5.67%	1.00	$	$	$ 94,440	$	$	$ (94,440)
	$ 400,000			$	$	$ 100,180	$ 22,495	$ (28,235)	$ (94,440)
December 31, 2007									
Interest rate swaps	$ 150,000	5.04%	8.75	$	$	$ 1,792	$ 4,274	$ (6,066)	$
Interest rate swaps	250,000	5.54%	0.50			16,600		(16,600)	
	$ 400,000			$	$	$ 18,392	$ 4,274	$ (22,666)	$

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Based on December 31, 2008 market interest rates and balances, a loss of approximately $5.7 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.

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.

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):

	2009	2010	2011	2012	2013	Thereafter	Total
Long - term debt							
Fixed rate [(a)]	$ 2,078	$ 32,096	$ 2,116	$ 2,028	$ 226,955	$ 218,330	$ 483,603
Average interest rate	9.62%	8.16%	9.70%	9.53%	6.52%	6.91%	6.85%
Variable rate	$	$	$	$	$	$ 19,855	$ 19,855
Average interest rate						3.93%	3.93%
Total long - term debt	$ 2,078	$ 32,096	$ 2,116	$ 2,028	$ 226,955	$ 238,185	$ 503,458
Average interest rate	9.62%	8.16%	9.70%	9.53%	6.52%	6.67%	6.73%

(a) Excludes unamortized premium or discount.

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 December 31, 2008, our credit exposure (exclusive of retail customers of our regulated utility segments) was concentrated primarily with investment grade companies. Approximately 90% 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, 2008 and 2007, we had outstanding forward exchange contracts to purchase approximately $52.0 million and $28.0 million Canadian dollars, respectively. These contracts had a fair value of $(0.2) million and $(0.3) million at December 31, 2008 and 2007, respectively, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. All forward exchange contracts outstanding at December 31, 2008 were settled by January 26, 2009.

New Accounting Pronouncements

See Note 1 to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2008 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

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

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008, 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, 2008.

Our assessment of the effectiveness of our internal controls over financial reporting as of December 31, 2008 excluded the assets and operations acquired on July 14, 2008 in the Aquila Transaction, which are doing business as Black Hills Energy. Such exclusion was in accordance with SEC guidance that an assessment of a recently acquired business may be omitted in management s report on internal control over financial reporting, provided the acquisition took place within twelve months of management s evaluation. Collectively, Black Hills Energy comprised 38% of our consolidated assets at December 31, 2008, 37% of our consolidated revenues and 4% of our net income for the year ended December 31, 2008. Our disclosure controls and procedures were not materially impacted by the acquisition.

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, 2008. 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 over financial reporting of Black Hills Corporation and subsidiaries (the Company) as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company 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 Company s internal control over financial reporting based on our audit.

As described in *Management s Report on Internal Control over Financial Reporting*, management excluded from its assessment of internal control over financial reporting the assets and operations acquired on July 14, 2008 in the Aquila Transaction, which are doing business as Black Hills Energy. Collectively, Black Hills Energy comprised 38% of total assets, 37% of revenues, and 4% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2008. Accordingly, our audit did not include the internal control over financial reporting of Black Hills Energy.

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 opinion.

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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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 and the financial statement schedule as of and for the year ended December 31, 2008, of the Company and our report dated March 2, 2009, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company s adoption of new accounting standards.

DELOITTE & TOUCHE LLP

Minneapolis, MN

March 2, 2009

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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 Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements are the responsibility of the Company 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 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.

The Company adopted Financial Accounting Standard Board s (FASB) Emerging Issues Task Force Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*, on January 1, 2006, Statement of Financial Accounting Standard (SFAS) No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, on December 31, 2006, and Financial Accounting Standards Board Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109,* on January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009, expressed an unqualified opinion on the Company s internal control over financial reporting.

DELOITTE & TOUCHE LLP

Minneapolis, MN

March 2, 2009

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BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2008 (in thousands)	2007	2006
Revenues:			
Operating revenues	$ 1,005,790	$ 574,838	$ 542,585
Operating expenses:			
Fuel and purchased power	449,742	161,006	191,651
Operations and maintenance	121,264	68,755	62,732
Administrative and general	138,568	111,337	88,562
Depreciation, depletion and amortization	107,263	71,767	67,515
Taxes, other than income taxes	41,294	32,943	29,989
Impairment of long-lived assets (Notes 1 and 12)	91,782	3,315	
	949,913	449,123	440,449
Operating income	55,877	125,715	102,136
Other income (expense):			
Interest expense	(54,123)	(25,181)	(29,946)
Interest rate swap (Note 2)	(94,440)		
Interest income	2,176	3,565	1,764
Allowance for funds used during construction - equity	3,835	4,803	2,647
Other expense	(187)	(347)	(132)
Other income	1,064	761	753
	(141,675)	(16,399)	(24,914)
Income (loss) from continuing operations before minority interest and income taxes	(85,798)	109,316	77,222
Equity in earnings (loss) of unconsolidated subsidiaries	4,366	(1,231)	1,653
Minority interest	(130)	(377)	(510)
Income tax benefit (expense)	29,395	(32,427)	(23,103)
Income (loss) from continuing operations	(52,167)	75,281	55,262
Income from discontinued operations, net of income taxes	157,247	23,491	25,757
Net income available for common stock	$ 105,080	$ 98,772	$ 81,019
Earnings (loss) per share of common stock:			
Basic-			
Continuing operations	$ (1.37)	$ 2.03	$ 1.67
Discontinued operations	4.12	0.63	0.77
Total	$ 2.75	$ 2.66	$ 2.44
Diluted-			
Continuing operations	$ (1.37)	$ 2.01	$ 1.65
Discontinued operations	4.12	0.63	0.77
Total	$ 2.75	$ 2.64	$ 2.42
Weighted average common shares outstanding:			
Basic	38,193	37,024	33,179
Diluted	38,193	37,414	33,549

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,	2008	2007
ASSETS	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 168,491	$ 76,889
Restricted cash		5,443
Accounts receivable (net of allowance for doubtful accounts of $6,751 and $4,588, respectively)	357,404	268,462
Materials, supplies and fuel	118,021	88,580
Derivative assets	73,068	35,921
Income tax receivable	20,269	
Deferred income taxes	10,244	4,512
Regulatory assets	35,390	2,307
Other current assets	16,380	10,391
Assets of discontinued operations	246	572,731
	799,513	1,065,236
Investments	22,764	19,216
Property, plant and equipment	2,705,492	1,847,435
Less accumulated depreciation and depletion	(683,332)	(509,187)
	2,022,160	1,338,248
Other assets:		
Goodwill	359,290	11,482
Intangible assets, net	4,884	3
Derivative assets	9,799	2,492
Regulatory assets	143,705	18,692
Other	17,774	14,265
	535,452	46,934
	$ 3,379,889	$ 2,469,634
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 288,907	$ 239,177
Accrued liabilities	134,940	96,207
Derivative liabilities	118,657	39,380
Accrued income taxes		833
Regulatory liabilities	5,203	4,779
Notes payable	703,800	37,000
Current maturities of long-term debt	2,078	130,326
Liabilities of discontinued operations	88	91,233
	1,253,673	638,935
Long-term debt, net of current maturities	501,252	503,301
Deferred credits and other liabilities:		
Deferred income taxes	223,607	207,735
Derivative liabilities	22,025	9,375
Regulatory liabilities	38,456	28,303
Benefit plan liabilities	159,034	41,699
Other	131,306	65,264
	574,428	352,376
Minority interest		5,167
Commitments and contingencies (Notes 7, 8, 9, 13, 17, 18 and 19)		
Stockholders equity:		
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 38,676,054 shares at 2008 and 37,842,221 shares at 2007	38,676	37,842
Additional paid-in capital	584,582	560,475
Retained earnings	447,453	397,393
Treasury stock at cost 40,183 shares at 2008 and 45,916 shares at 2007	(1,392)	(1,347)

Accumulated other comprehensive loss		(18,783)		(24,508)
		1,050,536		969,855
	$	3,379,889	$	2,469,634

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,	2008	2007	2006
	(in thousands)		
Operating activities:			
Net income	$ 105,080	$ 98,772	$ 81,019
Income from discontinued operations, net of tax	(157,247)	(23,491)	(25,757)
Income (loss) from continuing operations	(52,167)	75,281	55,262
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities-			
Depreciation, depletion and amortization	107,263	71,767	67,515
Impairment of long-lived assets	91,782	3,315	
Issuance of common stock and treasury stock for operating expense	2,657	4,585	2,760
Unrealized mark-to-market charge on certain interest rate swaps	94,440		
Net change in derivative assets and liabilities	(36,847)	(12,354)	19,755
Deferred income taxes	2,058	31,409	33,233
Change in operating assets and liabilities-			
Materials, supplies and fuel	14,525	18,197	(8,042)
Accounts receivable and other current assets	(50,955)	(27,510)	(2,875)
Accounts payable and other current liabilities	(21,453)	49,897	22,919
Regulatory assets and liabilities	(35,874)	(9,433)	18,879
Other operating activities	12,159	6,562	12,272
Net cash provided by operating activities of continuing operations	127,588	211,716	221,678
Net cash provided by operating activities of discontinued operations	18,053	44,572	38,593
Net cash provided by operating activities	145,641	256,288	260,271

Investing activities: