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 | IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

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

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

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

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

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No x

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

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

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

(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

(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.

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.

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.

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

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.

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)	2 to 4 Years (2011 – 2013)	Greater than 4 Years (2014 and beyond)	Total Volume
		(Bcf of natural gas)		
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.

2008 Compared to 2007

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 (in thousands)	2006
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	2007 (in thousands)	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

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	2007	2006
		(in thousands)	
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	2007 (in thousands)	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	2007 (in thousands)	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 (in thousands)	2006
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.

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	Impact on 2008 Service and Interest Cost
	(in thousands)	
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	Borrowings and Letters of Credit Issued at December 31, 2008
		(in millions)	
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, 2009. The 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.

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 (in thousands)	2006
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	2010 (in thousands)	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

<u>2008</u>

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.

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.

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)]

(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.

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	December 31, 2007
	(in thousands)	
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

(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

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)	$ —

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

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2008	2007	2006
		(in thousands)	
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:			
Property, plant and equipment additions	(328,922)	(205,213)	(301,034)
Payment for acquisition of net assets, net of cash acquired	(938,423)	—	—
Proceeds from sale of business operations	835,592	—	40,735
Other investing activities	4,537	(3,360)	(905)
Net cash used in investing activities of continuing operations	(427,216)	(208,573)	(261,204)
Net cash used in investing activities of discontinued operations	(29,836)	(55,908)	(7,469)
Net cash used in investing activities	(457,052)	(264,481)	(268,673)
Financing activities:			
Dividends paid on common stock	(53,663)	(50,300)	(43,960)
Common stock issued	2,683	150,787	3,213
Increase (decrease) in short-term borrowings, net	666,800	(108,500)	90,500
Long-term debt – issuance	—	110,000	—
Long-term debt – repayments	(130,297)	(35,033)	(4,302)
Other financing activities	(12,907)	(2,178)	(964)
Net cash provided by financing activities of continuing operations	472,616	64,776	44,487
Net cash used in financing activities of discontinued operations	(73,928)	(12,858)	(32,753)
Net cash provided by financing activities	398,688	51,918	11,734
Increase in cash and cash equivalents	87,277	43,725	3,332
Cash and cash equivalents:			
Beginning of year	81,255 (b)	37,530 (c)	34,198 (d)
End of year	$ 168,532 (a)	$ 81,255 (b)	$ 37,530 (c)
Supplemental disclosure of cash flow information:			
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$ 23,067	$ 19,734	$ 25,022
Issuance of common stock for Earnout Settlement (See Note 18)	$ 19,694	$ —	$ —
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 55,864	$ 44,700	$ 48,905
Income taxes paid (refunded)	$ 32,988	$ 14,204	$ (2,685)

(a) Includes approximately $41,000 of cash included in assets of discontinued operation.
(b) Includes approximately $4.4 million of cash included in the assets of discontinued operations.
(c) Includes approximately $5.0 million of cash included in the assets of discontinued operations.
(d) Includes approximately $11.6 million of cash included in the assets of discontinued operations.

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

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

	Year Ended December 31,		
	2008	2007	2006
	(in thousands, except share amounts)		
Common stock:			
Balance beginning of year	$ 37,842	$ 33,405	$ 33,223
Issuance of common stock	834	4,437	182
Balance end of year (38,676,054 shares, 37,842,221 shares and 33,404,902 shares issued in 2008, 2007 and 2006, respectively)	38,676	37,842	33,405
Additional paid-in capital:			
Balance beginning of year	560,475	409,826	404,035
Issuance of common stock	23,762	150,630	5,791
Issuance of treasury stock, net of purchases	345	19	—
Balance end of year	584,582	560,475	409,826
Retained earnings:			
Balance beginning of year	397,393	348,245	313,217
Net income	105,080	98,772	81,019
Dividends on common stock	(53,663)	(50,300)	(43,960)
Cumulative effect of change in accounting principle (see Notes 1, 14 and 17)	(1,357)	676	(2,031)
Balance end of year	447,453	397,393	348,245
Treasury stock:			
Balance beginning of year	(1,347)	(920)	(1,766)
(Purchase) issuance of treasury stock, net	(45)	(427)	846
Balance end of year (40,183 shares, 45,916 shares and 35,700 shares issued in 2008, 2007 and 2006, respectively)	(1,392)	(1,347)	(920)
Accumulated other comprehensive (loss):			
Balance beginning of year	(24,508)	(515)	(9,830)
Other comprehensive (loss) income, net of tax (see Note 15)	5,725	(23,993)	15,429
Adoption of accounting pronouncement (see Note 17)	—	—	(6,114)
Balance end of year	(18,783)	(24,508)	(515)
Total stockholders' equity	$ 1,050,536	$ 969,855	$ 790,041

	Year Ended December 31,		
	2008	2007	2006
	(in thousands)		
Comprehensive income:			
Net income available for common stock	$ 105,080	$ 98,772	$ 81,019
Other comprehensive (loss) income, net of tax (see Note 15)	5,725	(23,993)	15,429
	$ 110,805	$ 74,779	$ 96,448

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

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a diversified energy company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, operates in two primary business groups: Utilities and Non-regulated Energy. The Utilities Group includes two financial reporting segments: Electric Utilities and Gas Utilities. Electric Utilities include the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. Gas Utilities consist of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas and Nebraska Gas.

The Non-regulated Energy Group includes four financial reporting segments: Oil and Gas, Power Generation, Coal Mining and Energy Marketing. Oil and Gas, which is conducted through BHEP and its subsidiaries, engages in oil and natural gas production activities. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in power generation activities. Coal Mining, which is conducted through WRDC, engages in coal mining activities. Energy Marketing, which is conducted through Enserco, engages in natural gas and crude oil marketing activities. All of these businesses are aggregated for reporting purposes as Black Hills Non-Regulated Holdings.

For further descriptions of our business segments, see Note 20.

On July 14, 2008, we completed the acquisition of a regulated electric utility in Colorado and regulated gas utilities in Colorado, Iowa, Kansas and Nebraska from Aquila. Effective as of the acquisition date, the assets and liabilities, results of operations and cash flows of the acquired utilities are included in our Consolidated Financial Statements. See Note 21 for additional information.

On July 11, 2008, we completed the sale of seven IPP plants. For all periods presented, amounts associated with the divested IPP plants have been classified as discontinued operations on the accompanying Consolidated Financial Statements. See Note 16 for additional information.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to allowance for uncollectible accounts receivable, unbilled revenues, market value of derivatives, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, employee benefit plans, asset retirement obligations and contingencies related to taxes, legal and regulatory matters. Actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries. Generally, we use the equity method of accounting for investments of which we own between 20 and 50% and investments in partnerships under 20% if we exercise significant influence. In May 2003, our subsidiary, Black Hills Wyoming, entered into an agreement with Wygen Funding, LP (a VIE), to lease the Wygen I plant. We were considered the primary beneficiary of the plant and therefore, consolidated Wygen Funding under FIN 46(R). In June 2008, we purchased the Wygen I plant. Since the plant was previously consolidated into our financial statements, the transaction had minimal impact on our Consolidated Financial Statements.

All intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with regulated intercompany fuel sales in accordance with the provisions of SFAS 71. Total intercompany fuel sales not eliminated were $47.5 million, $13.2 million and $10.8 million in 2008, 2007 and 2006, respectively. Our consolidated statements of income include operating activity of acquired companies beginning with their acquisition date.

We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in the jointly owned Black Hills Power transmission tie, the Wyodak power plant and the BHEP gas processing plant. See Note 6 for additional information.

Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Materials, Supplies and Fuel

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

		2008		2007
		(in thousands)		
Major Classification				
Materials and supplies	$	32,580	$	27,649
Fuel – Electric Utilities		10,058		5,025
Gas supply – Gas Utilities		59,529		—
Gas and oil held by Energy Marketing*		15,854		55,906
Total materials, supplies and fuel	$	118,021	$	88,580

* As of December 31, 2008 and 2007, market adjustments related to Gas and oil held by Energy Marketing and recorded in inventory, were $(9.4) million and $(9.8) million, respectively. (See Note 2 for further discussion of Energy Marketing trading activities.)

The increase in gas supply is due to additions of natural gas storage inventory for the gas utilities acquired in July 2008.

Materials and supplies, Fuel – Electric Utilities, and Gas supply – Gas Utilities are valued on a weighted-average cost basis.

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

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. In addition, we also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $8.0 million, $14.8 million and $7.2 million in 2008, 2007 and 2006, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Ordinary repairs and maintenance of property are charged to operations as incurred.

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

Oil and Gas Operations

We account for our oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated dismantlement and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized.

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

Under the full cost method, net capitalized costs are subject to a ceiling test which limits these costs to the present value of future net cash flows discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on end-of-period spot market commodity prices adjusted for contracted price changes. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period unless subsequent changes in facts, such as market price increases, eliminate or reduce the indicated write-down.

As a result of low crude oil and natural gas prices at December 31, 2008, we recorded a pre-tax non-cash ceiling test impairment of our oil and gas assets totaling $91.8 million. The write-down of gas and oil properties was based on December 31, 2008 NYMEX spot 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. No ceiling test write-downs were recorded during 2007 or 2006.

Given the volatility of oil and gas prices, our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that another write-down of oil and gas properties could occur in the future.

Goodwill and Intangible Assets

We account for goodwill and intangible assets in accordance with SFAS 142. Under SFAS 142, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed annually for impairment. Intangible assets with a finite life continue to be amortized over their estimated useful lives. We perform this annual review of goodwill and intangible assets during the fourth quarter of each year (or more frequently if impairment indicators arise).

The substantial majority of our goodwill and intangible assets are contained within the Utilities Group relating to the 2008 purchase of utility properties in the Aquila Transaction. Changes to goodwill and intangible assets during the years ended December 31, 2008 and 2007 are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2006, net of accumulated amortization	$ 12,168	$ 402
Tax adjustment on acquisition earn-out (see Note 18)	(92)	—
Impairment losses	(594)	(314)
Amortization expense	—	(85)
Balance at December 31, 2007, net of accumulated amortization	11,482	3
Additions	347,808	4,919
Amortization expense	—	(38)
Balance at December 31, 2008, net of accumulated amortization	$ 359,290	$ 4,884

On July 14, 2008, we completed the acquisition of regulated electric and gas utilities from Aquila. Allocation of the purchase price included $344.5 million of goodwill and $4.9 million of intangible assets (see Note 21).

The acquisition of the Aquila assets has been accounted for under purchase accounting, whereby the purchase price of the transaction was allocated to identifiable assets acquired and liabilities assumed based upon their fair values. The estimates of the fair values recorded were determined based on the principles in SFAS 157 and reflect significant assumptions and judgments. We comply with the provisions of SFAS 71 and thus the assets and settlement of liabilities are subject to cost-based regulatory rate-setting processes. Accordingly, the historical carrying values of a majority of our assets and liabilities are deemed to represent fair values.

During 2008, we adjusted goodwill $3.3 million for issuance of shares of common stock related to the settlement of the Earn-out Litigation with former Indeck shareholders. See Notes 10 and 18 for additional information.

In accordance with SFAS 142, we tested goodwill for impairment in the fourth quarter. We estimated the fair value of the goodwill using discounted cash flow methodology and an analysis of comparable companies' transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples for comparable companies. We believe that the goodwill amount reflects the value of the relatively stable, long-lived cash flows of the regulated utility business, considering the regulatory environment and market growth potential.

Intangible assets represent easements, right-of-way and trademarks and are amortized using a straight-line method using estimated useful lives of 20 years. Intangible assets totaled $4.9 million, with accumulated amortization less than $0.1 million at December 31, 2008 and intangible assets totaled less than $0.1 million, net of accumulated amortization at December 31, 2007. Amortization expense for intangible assets was $0.1 million in each of 2008, 2007 and 2006, respectively. Amortization expense for existing intangible assets is expected to be $0.2 million a year through 2013.

During the third quarter of 2007, we wrote off intangible assets of $0.3 million, net of accumulated amortization of $0.8 million, related to the impairment of the Ontario plant. The impairment charge is a result of a thermal host contract expiration without a long-term extension. See Note 12 for additional information.

During the second quarter of 2007, we wrote off goodwill of approximately $0.1 million for tax adjustments related to the Indeck acquisition earn-out (see Note 18). During the fourth quarter of 2007, we wrote off goodwill of approximately $0.6 million, net of accumulated amortization of $0.1 million, related to the write-down of our investments in the Rupert and Glenns Ferry partnerships. The write-downs were the result of impairment charges by the partnerships primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of the partnerships’ power supply agreements (see Note 12).

Asset Retirement Obligations

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

Impairment of Long-lived Assets

We periodically evaluate whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of our long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, we would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, we would recognize an impairment loss. In 2007, we recorded a $2.7 million pre-tax impairment charge to reduce the carrying value of the Ontario power plant and related intangibles and a $0.6 million pre-tax impairment charge of goodwill related to lower partnership earnings as a result of a partnership impairment charge for the Glenns Ferry and Rupert power plants, in which we hold a 50% interest and account for under the equity method.

Derivatives and Hedging Activities

We account for derivative and hedging activities in accordance with SFAS 133. SFAS 133 requires that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative instrument’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

SFAS 133 allows hedge accounting for qualifying fair value and cash flow hedges. SFAS 133 provides that the gain or loss on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

Currency Adjustments

Our functional currency for all operations is the United States dollar. Through Enserco, we engage in natural gas business transactions in Canada and accordingly, have various transactions that have been denominated in Canadian dollars. These Canadian denominated transactions/balances are adjusted to United States dollars for financial reporting purposes using the year-end exchange rate for balance sheet items and an average exchange rate during the period for income statement items. Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Operating revenues on the accompanying Consolidated Statements of Income as incurred. The amount of unrealized gains was $0.3 million, $0.2 million and $0.3 million in 2008, 2007 and 2006, respectively, and the amount of realized losses was $1.4 million, $1.7 million and $1.0 million in 2008, 2007 and 2006, respectively.

Deferred Financing Costs

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

Development Costs

We generally expense, when incurred, development and acquisition costs associated with corporate development activities prior to acquiring or beginning construction of a project. Expensed development costs are included in Administrative and general operating expenses on the accompanying Consolidated Statement of Income. Upon adoption of SFAS 141(R) in 2009, all acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered.

Legal Costs

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

Minority Interest in Subsidiaries

Minority interest in the accompanying Consolidated Statements of Income and Balance Sheets represents the non-affiliated equity investors' interest in Wygen Funding, L.P., a VIE as defined by FIN 46(R).

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

Regulatory Accounting

Our Utilities Group is subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses.

The regulated utilities follow the provisions of SFAS 71, and their financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating the utilities. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply. In the event we determine that Black Hills Power, Cheyenne Light, Iowa Gas, Nebraska Gas, Kansas Gas, Colorado Gas or Colorado Electric no longer meets the criteria for following SFAS 71, the accounting impact to the Company could be an extraordinary non-cash charge to operations, which could be material.

On December 31, 2008 and 2007, we had the following regulatory assets and liabilities:

	2008	2007
	(in thousands)	
Regulatory assets		
Deferred energy and fuel costs adjustments	$ 32,198	$ 1,931
Deferred gas cost adjustments and gas price derivatives	25,364	376
Allowance for funds used during construction	8,719	7,880
Employee benefit plans	98,414	2,998
Environmental	2,406	—
Asset retirement obligations	2,598	—
Bond issue cost	4,121	4,276
Other	5,275	3,538
	$ 179,095	$ 20,999
Regulatory liabilities		
Deferred energy and gas costs	$ 2,417	$ 4,779
Cost of removal	31,351	22,431
Employee benefit plans	1,513	1,738
Revenue subject to refund	2,786	—
Other	5,592	4,134
	$ 43,659	$ 33,082

Regulatory assets are primarily recorded for the probable future revenue to recover the costs associated with regulated utilities' defined benefit postretirement plans, future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets and unrecovered energy and fuel costs.

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

- Our gas utilities have PGA provisions that allow them to pass the cost of gas to their customers. In addition, as allowed by state utility commissions, we have entered into certain exchange traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. To the extent that gas costs are under-recovered or over-recovered, they are recorded as regulatory assets or liabilities, respectively.

- AFUDC represents the approximate composite cost of borrowed funds and a return on equity used to finance a project. AFUDC for the years ended December 31, 2008, 2007 and 2006 was $6.6 million, $11.2 million, and $5.6 million, respectively. The equity component of AFUDC for 2008, 2007 and 2006 was $3.8 million, $4.8 million and $2.6 million, respectively. The borrowed funds component of AFUDC for 2008, 2007 and 2006 was $2.8 million, $6.4 million and $3.0 million, respectively. The equity component of AFUDC is included in Other income (expense), and the borrowed funds component of AFUDC is included in Interest expense on the accompanying Consolidated Statements of Income.

- Deferred energy and fuel cost adjustments represents the cost of electricity delivered to our electric utility customers in excess of current rates that will be recovered in future rates.

- Asset retirement obligations represent the estimated recoverable costs for legally required removal obligations. See Note 9 for additional details.

- In connection with SFAS 158, our Regulated Utilities reflect the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans as regulatory assets rather than in accumulated other comprehensive income. In connection with the Aquila Transaction, we recorded $29.7 million through the purchase price allocation.

Regulatory liabilities represent items we expect to pay to customers through probable future decreases in rates.

- Deferred energy costs related to decreases in purchased power, transmission and natural gas costs charged to Cheyenne Light customers through a PCA and GCA mechanism.

- Cost of removal for utility plant represents the estimated cumulative net provisions for future removal costs included in depreciation expense for which there is no legal removal obligation.

- Pension represents the cumulative excess of pension costs recovered in rates over pension expense recorded under SFAS 87.

- Revenues subject to refund represent revenues collected from customers under interim rate orders that may be refunded to customers pending the outcome of final rate orders.

Income Taxes

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

We use the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. We classify deferred tax assets and liabilities into current and non-current amounts based on the classification of the related assets and liabilities.

We account for uncertainty in income taxes recognized in the financial statements in accordance with FIN 48. The unrecognized tax benefit is classified in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheet. See Note 14 for additional information.

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured.

Utility revenues are based on authorized rates approved by the state regulatory agencies and FERC. Revenues related to the sale, transmission and distribution of energy delivery service are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on systematic meter readings throughout a month. Meters that are not read during a given month are estimated and trued-up to actual use in a future period. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and the corresponding unbilled revenue is recorded. The amount of unbilled revenues recorded in Accounts receivable on the Consolidated Balance Sheets as of December 31, 2008 and 2007 were $73.0 million and $5.8 million, respectively.

In addition, in accordance with SFAS 133 certain energy marketing activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In accordance with EITF 02-3, all energy marketing contracts that do not meet the definition of derivatives as defined by SFAS 133, have been accounted for under the accrual method of accounting.

For long-term non-utility power sales agreements revenue is recognized either in accordance with EITF 91-6, or in accordance with SFAS 13 as appropriate. Under EITF 91-6, revenue is generally recognized as the lower of the amount billed or the average rate expected over the life of the agreement.

For our Investment in Associated Companies (see Note 4), which are involved in power generation, we use the equity method to recognize our pro rata share of the net income or loss of the associated company.

We present our operating revenues from energy marketing operations in accordance with the guidance provided in EITF 02-3 and EITF 99-19. Accordingly, gains and losses (realized and unrealized) on transactions at our natural gas and crude oil marketing operations are presented on a net basis in operating revenues, whether or not settled physically.

Earnings per Share of Common Stock

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

	2008		2007		2006	
	(Loss)	Average Shares	Income	Average Shares	Income	Average Shares
Basic – Income (loss) from continuing operations	$ (52,167)	38,193	$ 75,281	37,024	$ 55,262	33,179
Dilutive effect of:						
Stock options	—	—	—	111	—	87
Contingent shares issuable for prior acquisition	—	—	—	159	—	159
Others	—	—	—	120	—	124
Diluted – Income (loss) from continuing operations	$ (52,167)	38,193	$ 75,281	37,414	$ 55,262	33,549

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

	2008	2007	2006
Options to purchase common stock	—	34	153

Recently Adopted Accounting Pronouncements

EITF 04-6

The Company adopted EITF 04-6 on January 1, 2006. EITF 04-6 provides that stripping costs incurred in our mining operations should be included in the costs of inventory produced during the period the costs are incurred. Upon adoption of EITF 04-6 on January 1, 2006, the Company recorded a $2.0 million cumulative effect adjustment to write off previously recorded deferred charges with the offset decreasing retained earnings.

SFAS 157

During September 2006, the FASB issued SFAS 157. This Statement defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 does not expand the application of fair value accounting to any new circumstances, but applies the framework to other accounting pronouncements that require or permit fair value measurement. We apply fair value measurements to certain assets and liabilities, primarily commodity derivatives within our Energy Marketing and Oil and Gas segments, interest rate swap derivative instruments, and other miscellaneous derivatives.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. As of January 1, 2008, we adopted the provisions of SFAS 157 for all assets and liabilities measured at fair value except for non-financial assets and liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2. As a result of adopting SFAS 157, we discontinued our use of a “liquidity reserve” in valuing the total forward positions within our energy marketing portfolio. This impact was accounted for prospectively as a change in accounting estimate and resulted in a $1.2 million after-tax benefit being recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Operating revenues on the accompanying Consolidated Statements of Income. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with instruments carried at fair value. This additional disclosure is provided in Notes 3 and 11.

FSP FAS 157-1

In February 2008, the FASB issued FSP FAS 157-1, which excludes SFAS 13 and other accounting pronouncements that address fair value for purposes of lease classification and measurement under SFAS 13 from SFAS 157 except when applying SFAS 157 to assets acquired and liabilities assumed in a business combination. We applied the provisions of FSP FAS 157-1 from the date of initial adoption of SFAS 157 on January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to lease transactions under SFAS 13 except when applying SFAS 157 to business combinations.

FSP FAS 157-2

In February 2008, the FASB issued FSP FAS 157-2, which permits a one-year deferral of the application of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted FSP FAS 157-2 effective January 1, 2008. Accordingly, the provisions of SFAS 157 will not be applied to non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. We are currently evaluating the impact, if any, that the deferred provisions of SFAS 157 will have on our consolidated financial statements.

SFAS 158

During September 2006, the FASB issued SFAS 158. This statement requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. We applied the recognition provisions of SFAS 158 as of December 31, 2006. Effective for fiscal years ending after December 15, 2008, SFAS 158 requires the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. In compliance with SFAS 158, the measurement date for the funded status of our pension and other postretirement benefit plans was changed to December 31 from September 30. See Note 17 for additional information.

SFAS 159

SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. SFAS 159 was adopted on January 1, 2008 and did not have an impact on our consolidated financial position, results of operations or cash flows.

FSP FIN 39-1

FSP FIN 39-1 amends certain paragraphs of FIN 39 to permit a reporting entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. We adopted FSP FIN 39-1 effective January 1, 2008. This standard changed our method of netting certain balance sheet amounts. We applied FSP FIN 39-1 as a change in accounting principle through retrospective application. Each Consolidated Balance Sheet herein reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when we believe a legal right of offset exists.

On July 11, 2008, the Company sold seven of its IPP plants. Amounts associated with the IPP plants divested have been classified as discontinued operations. Therefore this classification is also reflected in the Consolidated Balance Sheet and Consolidated Statement of Cash Flows.

Accordingly, December 31, 2007 and 2006 amounts have been reclassified to conform to this presentation as follows (in thousands):

Balance Sheet Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2007
Current assets:				
Receivables	$ 291,189	$ (1,945)	$ (20,782)	$ 268,462
Derivative assets	$ 37,208	$ (1,287)	$ —	$ 35,921
Current liabilities:				
Accounts payable	$ 242,813	$ (3,232)	$ (404)	$ 239,177

The affect on the Cash Flow Statements for 2007 and 2006 due to the reclassification are as follows (in thousands):

Cash Flow Statement Operating Activities Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2007
Accounts receivable and other current assets	$ (32,808)	$ 1,945	$ 3,353	$ (27,510)
Net change in derivative assets and liabilities	$ (10,763)	$ (1,591)	$ —	$ (12,354)
Accounts payable and other current liabilities	$ 49,258	$ (354)	$ 993	$ 49,897

Cash Flow Statement Operating Activities Line Description	Previously Reported at December 2007	FSP FIN 39-1 Reclassification	Discontinued Operations Reclassification	Restated December 2006
Accounts receivable and other current assets	$ 2,208	$ (8,013)	$ 2,930	$ (2,875)
Net change in derivative assets and liabilities	$ 8,864	$ 10,891	$ —	$ 19,755
Accounts payable and other current liabilities	$ 28,853	$ (2,878)	$ (3,056)	$ 22,919

As of December 31, 2007 and 2006, we offset fair value cash collateral receivables and payables against net derivative positions in the amounts of $(1.3) million and $(2.9) million, respectively.

Recently Issued Accounting Pronouncements

SEC Final Rule #33-8995

On December 29, 2008, the SEC released Final Rule, “Modernization of Oil and Gas Reporting” amending the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technology advances. Key revisions include the ability to include non-traditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The amendment is effective January 1, 2010 and early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, financial position and cash flows.

SFAS 141(R)

In December 2007, the FASB issued SFAS 141(R). SFAS 141(R) requires an acquiring entity to recognize the assets acquired, the liabilities assumed and any non-controlling interests in the acquiree at the acquisition date to be measured at their fair values as of the acquisition date, with limited exceptions specified in the statement. This replaces the cost allocation process in SFAS 141, which required the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. Acquisition-related costs will be expensed in the periods in which the costs are incurred or services are rendered. Costs to issue debt or equity securities shall be accounted for under other applicable GAAP. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after December 15, 2008. We expect SFAS 141(R) will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of any acquisitions we consummate after the effective date. If income tax liabilities are settled for an amount other than as previously recorded prior to the adoption of SFAS 141(R), the reversal of any remaining liability will affect goodwill or the financial reporting basis in the applicable assets acquired. If previously recorded income tax liabilities acquired in a business combination reverse subsequent to the adoption of SFAS 141(R), such reversals will affect expense including income tax expense in the period of reversal. We are assessing the full impact SFAS 141(R) might have on future consolidated financial statements.

SFAS 160

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

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

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

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

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

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

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

SFAS 161

In March 2008, the FASB issued SFAS 161, which requires enhanced disclosures about how derivative and hedging activities affect an entity's financial position, financial performance and cash flows. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of SFAS 161 will require additional disclosures regarding our derivative instruments; however, it will not impact our financial position or results of operations.

FSP FAS 132(R)-1

During December 2008 the FASB issued FSP FAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets in a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of:

- How investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies;
- The major categories of plan assets;
- The input and valuation techniques used to measure the fair value of plan assets;
- The effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and
- Significant concentrations of risk within plan assets.

FSP FAS 132(R)-1 is effective for fiscal years ending after December 15, 2009. We do not expect the adoption of FSP FAS 132(R)-1 to have a significant effect on our consolidated financial statements.

(2) RISK MANAGEMENT ACTIVITIES

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

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

- Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, and fuel procurement for certain of our gas-fired generation assets variability in revenue due to changes in gas usage at our Gas Utilities Segment resulting from commodity price changes;
- Interest rate risk associated with variable rate credit facilities floating rate debt as described in Notes 7 and 8; and
- Foreign currency exchange risk associated with natural gas marketing business transacted in Canadian dollars.

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.

Trading Activities

Natural Gas and Crude Oil Marketing

To manage our marketing portfolios, Enserco enters into forward physical commodity contracts, financial instruments including over-the-counter swaps and options, transportation agreements, storage agreements and forward foreign exchange contracts. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed by the BHCRPP and the Gas and Oil Marketing Risk Policies and Procedures.

For the years ended December 31, 2008, 2007 and 2006, contracts and other activities at our natural gas and crude oil marketing operations are accounted for under the provisions of EITF 02-3 and SFAS 133. As such, all of the contracts and other activities at our natural gas and crude oil marketing operations that meet the definition of a derivative under SFAS 133 are accounted for at fair value. The fair values are recorded as either Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Consolidated Statements of Income. EITF 02-3 precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to SFAS 133. As part of our natural gas and crude oil marketing operations, we often employ strategies that include derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our producer services, end-use origination and wholesale marketing groups. Except in limited circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, SFAS 133 generally does not allow us to mark inventory, transportation or storage positions to market. The result is that while a significant majority of our natural gas and crude oil marketing positions are economically hedged, we are required to mark some parts of our overall strategies (the derivatives) to market value, but are generally precluded from marking the rest of our economic hedges (transportation, inventory or storage) to market. Volatility in reported earnings and derivative positions result from these accounting requirements.

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

	2008		2007	
	Notional Amounts	Latest expiration (months)	Notional Amounts	Latest expiration (months)
(thousands of MMBtu)				
Natural gas basis swaps purchased	187,368	34	125,577	36
Natural gas basis swaps sold	186,710	34	128,892	36
Natural gas fixed-for-float swaps purchased	85,412	24	42,326	24
Natural gas fixed-for-float swaps sold	90,171	24	59,253	24
Natural gas physical purchases	131,937	16	90,583	15
Natural gas physical sales	145,706	21	98,888	27
Natural gas options purchased	1,440	3	3,472	10
Natural gas options sold	1,440	3	3,472	10
(thousands of Bbls of oil)				
Crude oil physical purchases	7,446	12	4,991	12
Crude oil physical sales	6,251	12	3,800	12
Crude oil swaps purchased	435	24	495	12
Crude oil swaps sold	502	24	495	12
(Dollars, in thousands)				
Canadian dollars purchased	$52,000	1	$28,000	2

Derivatives and certain natural gas and oil marketing activities were marked to fair value on December 31, 2008 and 2007, and the gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income as of December 31, 2008 and 2007 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Cash Collateral Included in Derivative Asset/ Liabilities	Unrealized Gain
December 31, 2008	$ 52,723	$ (145)	$ 15,553	$ (777)	$ 16,315	$ 54,117
December 31, 2007	$ 30,999	$ 1,901	$ 16,908	$ 2,482	$ 1,287	$ 14,797

In addition, certain volumes of natural gas inventory have been designated as the underlying hedged item in a "fair value" hedge transaction. These volumes include market adjustments based on published industry quotations. Market adjustments are recorded in inventory on the Consolidated Balance Sheets and the related unrealized gain/loss on the Consolidated Statements of Income effectively offsetting the earnings impact of the unrealized gain/loss recognized on the associated derivative asset or liability described above. As of December 31, 2008 and 2007, the market adjustments recorded in inventory were $(9.4) million and $(9.8) million, respectively.

Activities Other than Trading

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. Our natural “long” positions, or unhedged open positions, introduce commodity price risk and variability in our cash flows. We employ risk management methods to mitigate this commodity price risk and preserve cash flows and 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 are routinely reviewed by our Board of Directors.

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

At December 31, 2008 and 2007, we had a portfolio of swaps and options to hedge portions of our crude oil and natural gas production. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. At year-end, these transactions met retrospective effectiveness testing criteria and retained their cash flow hedge status.

At December 31, 2008 and 2007, the derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On December 31, 2008 and 2007, we had the following swaps, options and related balances (in thousands):

December 31, 2008	Notional*	Maximum Duration in Years**	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Earnings
Crude oil swaps/options	435,000	0.25	$ 7,674	$ 3,464	$ —	$ 10	$ 9,642	$ 1,486
Natural gas swaps	8,523,500	1.00	11,828	3,749	—	297	15,280	—
			$ 19,502	$ 7,213	$ —	$ 307	$ 24,922	$ 1,486
December 31, 2007								
Crude oil swaps/options	495,000	1.00	$ 352	$ —	$ 3,506	$ 1,794	$ (5,300)	$ 352
Natural gas swaps	11,406,000	1.59	4,332	591	507	825	3,587	4
			$ 4,684	$ 591	$ 4,013	$ 2,619	$ (1,713)	$ 356

* Crude in Bbls, gas in MMBtu.

** Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the timing of the hedged transaction and the corresponding settlement of the derivative instrument.

Most of our crude oil and natural gas hedges are highly effective, resulting in limited earnings impact prior to realization. We estimate that a portion of the unrealized earnings currently recorded in accumulated other comprehensive income will be realized in earnings during 2009. Based on December 31, 2008 market prices, a $12.7 million gain will be realized and reported in earnings during 2009. These estimated realized gains for 2009 were calculated using December 31, 2008 market prices. Estimated and actual realized gains will likely change during 2009 as market prices change.

Regulated Gas Utilities

Our regulated gas utilities have PGA provisions that allow them to pass the cost of gas to the consumer. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. These adjustments are subject to periodic prudence reviews by the respective state utility commissions. In addition, as allowed or required by state utility commissions, we have entered into certain exchange traded natural gas futures and options transactions to reduce our customers' underlying exposure to fluctuations in gas prices. Gains or losses on the transactions are recorded as regulatory assets or liabilities. The futures and options transactions are considered derivative transactions under SFAS 133 and are marked-to-market and recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheet.

On December 31, 2008, the contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities are as follows:

	Notional*	Latest Expiration (months)
Natural gas futures purchased	1,290,000	3
Natural gas options purchased	3,990,000	3
Natural gas options sold	820,000	3

* Gas in MMBtu

On December 31, 2008, our Gas Utilities held the following derivative-related balances (in thousands):

	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Regulatory Assets	Cash Collateral Included in Derivative Assets/ Liabilities
December 31, 2008	$ 4,224	$ —	$ 2,924	$ —	$ 11,668	$ 8,744

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. We also had 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 values were 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. Cumulative and future mark-to-market adjustments on the swaps are now recorded within the income statement. During the fourth quarter of 2008, we recorded an unrealized mark-to-market charge to earnings of $94.4 million pre-tax. These swaps are ten and twenty year swaps which have amended mandatory early termination dates ranging from September 30, 2009 to December 29, 2009.

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 (Loss)	Pre-tax (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)	$ —

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 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. We cash settled the treasury lock on October 15, 2007, which was the pricing date of the offering. This settlement resulted in a $4.3 million payment to the counterparty. The payment was recorded as a regulatory asset and will be amortized over the life of the related bonds as additional interest expense.

Foreign Exchange Contracts

Enserco conducts its gas marketing business in the United States as well as Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange rate risk for us. 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 at December 31, 2008 and $(0.3) million at December 31, 2007, respectively, and have been recorded as Derivative assets/liabilities on the accompanying Consolidated Balance Sheets. The impact of foreign exchange transactions did not have a material effect on our Consolidated Statements of Income. All forward exchange contracts outstanding at December 31, 2008 were settled by January 26, 2009.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We adopted the BHCCP for the purpose of establishing guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by our Board of Directors. In addition, we have a credit committee which includes senior executives that meet on a regular basis to review our credit activities and monitor compliance with our credit policies.

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

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 review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At December 31, 2008, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Approximately 90% of the credit exposure was with investment grade companies. The remaining credit exposure was with non-investment grade or non-rated counterparties, of which a portion was supported through letters of credit, prepayments or parental guarantees.

(3) FAIR VALUE MEASUREMENTS

Adoption of SFAS 157

Effective January 1, 2008, we adopted SFAS 157 as discussed in Note 1. SFAS 157 requires, among other things, enhanced disclosures about assets and liabilities carried at fair value. SFAS 157 also provides a single definition of fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As permitted under SFAS 157, we utilize a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing a significant portion of the assets and liabilities measured and reported at fair value.

SFAS 157 also requires enhanced disclosures and establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values giving the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). We are able to classify fair value balances based on the observability of inputs.

Financial assets and liabilities carried at fair value are classified and disclosed in one of the following three categories:

Level 1 – Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities and listed derivatives.

Level 2 – Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

The following table sets forth, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect their placement within the fair value hierarchy levels.

Recurring Fair Value Measures (in thousands)	At Fair Value as of December 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting (a)	Total
Assets:					
Commodity derivatives	$ 8,744	$ 267,932	$ 28,407	$ (217,696)	$ 87,387
Liabilities:					
Commodity derivatives	$ 16,315	$ 211,672	$ 12,009	$ (217,696)	$ 22,300
Foreign currency derivatives	—	227	—	—	227
Interest rate swaps	—	122,675	—	—	122,675
Total	$ 16,315	$ 334,574	$ 12,009	$ (217,696)	$ 145,202

(a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between the Company and a contractual counterparty.

The following table presents the changes in level 3 recurring fair value for the three and twelve months ended December 31, 2008 (in thousands):

	Three Months Ended December 31, 2008		
	Commodity Derivatives	Short-term Investments	Total
Balance as of October 1, 2008	$ 6,321	$ 6,310	$ 12,631
Realized and unrealized gains	7,371	215	7,586
Purchases, issuance and (settlements)	2,706	(6,525)	(3,819)
Balances as of December 31, 2008	$ 16,398	$ —	$ 16,398
Changes in unrealized losses relating to instruments still held as of December 31, 2008	$ 6,527	$ 215	$ 6,742

	Year Ended December 31, 2008
	Commodity Derivatives
Balance as of January 1, 2008	$ 6,422
Realized and unrealized gains	11,059
Purchases, issuance and settlements	(1,083)
Balances as of December 31, 2008	$ 16,398
Changes in unrealized losses relating to instruments still held as of December 31, 2008	$ 1,886

Gains and losses (realized and unrealized) for level 3 commodity derivatives are included in Operating revenues on the Consolidated Statement of Income. We believe an analysis of commodity derivatives classified as level 3 needs to be undertaken with the understanding that these items may be economically hedged as part of a total portfolio of instruments that may be classified in level 1 or 2, or with instruments that may not be accounted for at fair value. Accordingly, gains and losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items may be offset by unrealized gains and losses in positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Short-term investments included in level 3 represent auction rate securities held during 2008 but sold prior to December 31, 2008.

(4) INVESTMENTS IN ASSOCIATED COMPANIES

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

- A 4.4% interest in Project Finance Fund III, L.P., which in turn has investments in numerous electric generating facilities in the United States and elsewhere. The carrying amount of our investment in the funds was $4.1 million and $3.0 million, as of December 31, 2008 and 2007, respectively. As of, and for the year ended December 31, 2008, the funds had assets of $22.4 million, liabilities of $0.1 million and net income of $10.0 million. As of, and for the year ended December 31, 2007, the funds had assets of $43.1 million, liabilities of $0.3 million and net income of $8.0 million. The Energy Investors Fund II, L.P. was fully liquidated as of December 31, 2008 and the Energy Investors Fund, L.P. was fully liquidated as of December 31, 2007. This investment is included in the Power Generation segment.

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

- A 50% interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The carrying amount in our investment was $0.8 as of December 31, 2008, and $0 million as of December 31, 2007. In December 2007, the Rupert and Glenns Ferry partnerships wrote down the carrying amounts of their property, plant and equipment to reflect the partnerships’ assessment of the recoverability of their respective carrying amounts primarily due to forecasted unhedged future commodity purchases during a significant portion of the remaining term of power supply agreements. As a result, our carrying amount of the two partnership investments was reduced by a total of $3.9 million to reflect equity losses from the partnerships’ asset impairment adjustments. In addition, we wrote off a total of $0.6 million of net goodwill for the two partnerships directly related to our 50% investments. This investment is included in the Power Generation segment. As of, and for the year ended December 31, 2008, these projects had assets of $6.4 million, liabilities of $6.0 million and net income of $3.4 million. As of, and for the year ended December 31, 2007, these projects had assets of $4.5 million, liabilities of $7.8 million and net income of $(11.6) million.

(5) PROPERTY, PLANT AND EQUIPMENT

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

Utilities Group

Electric Utilities	2008	2008 Weighted Average Useful Life	2007	2007 Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 531,872	46	$ 326,879	47	17-62
Transmission	94,115	45	73,383	45	35-56
Distribution	482,518	43	357,249	41	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	63,702	21	47,740	23	5-60
Total electric plant	1,177,077		810,121		
Less accumulated depreciation and amortization	303,273		276,646		
Electric plant net of accumulated depreciation and amortization	873,804		533,475		
Construction work in progress	169,759		200,804		
Net electric plant	$ 1,043,563		$ 734,279		

Gas Utilities	2008	2008 Weighted Average Useful Life	Lives (in years)
Gas plant:			
Production	$ 72	37	16-55
Transmission	23,299	54	22-60
Distribution	334,146	44	2-65
General	64,167	16	1-49
Total	421,684		
Less accumulated depreciation and amortization	13,328		
Total net of accumulated depreciation and amortization	408,356		
Construction work in progress	6,595		
Net Gas	$ 414,951		

Non — regulated Energy	2008						
	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$ 105,897	$ 49,562	$ 56,335	$ 1,563	$ 57,898	11	2-39
Oil and Gas	648,419	281,728	366,691	—	366,691	26	3-27
Energy Marketing	2,375	1,945	430	—	430	3	2-7
Power Generation	154,257	27,197	127,060	4,469	131,529	36	3-40
	$ 910,948	$ 360,432	$ 550,516	$ 6,032	$ 556,548		

Non — regulated Energy	2007						
	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Coal Mining	$ 81,046	$ 45,587	$ 35,459	$ 5,675	$ 41,134	15	3-25
Oil and Gas	559,394	153,050	406,344	—	406,344	24	3-25
Energy Marketing	2,389	1,603	786	—	786	4	2-7
Power Generation	155,208	24,294	130,914	20	130,934	35	3-40
	$ 798,037	$ 224,534	$ 573,503	$ 5,695	$ 579,198		

	2008						
	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Corporate	$ 12,482	$ 6,299	$ 6,183	$ 915	$ 7,098	4	3-10

	2007						
	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
Corporate	$ 19,474	$ 8,007	$ 11,467	$ 13,304	$ 24,771	4	3-10

(6) JOINTLY OWNED FACILITIES

Our subsidiary, Black Hills Power, owns a 20% interest in the Wyodak Plant (the Plant), a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining 80% and operates the Plant. Black Hills Power receives 20% of the Plant's capacity and is committed to pay 20% of its additions, replacements and operating and maintenance expenses. As of December 31, 2008, Black Hills Power's investment in the Plant included $79.1 million in electric plant and $50.8 million in Accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. Black Hills Power's share of direct expenses of the Plant was $8.0 million; $7.3 million and $7.9 million for the years ended December 31, 2008, 2007 and 2006, respectively, and are included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 18, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves. Under the coal supply agreement, PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustment for planned outages. WRDC's sales to the Plant were $23.3 million, $21.5 million and $16.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Black Hills Power also owns a 35% interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining 65%. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW – 200 MW West to East and 200 MW from East to West. Black Hills Power is committed to pay 35% of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2008, 2007 and 2006, Black Hills Power's share of direct expenses was $0.1 million for each year. As of December 31, 2008 and 2007, Black Hills Power's investment in the transmission tie was $19.8 million, with $2.5 million and $2.0 million of accumulated depreciation, respectively, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets.

Through our BHEP subsidiary, we own a 44.7% non-operating interest in the Newcastle Gas Plant (the Gas Plant). The natural gas processing facility gathers and processes approximately 3,000 Mcf/day of gas, primarily from the Finn-Shurley Field in Wyoming. We receive our proportionate share of the Gas Plant's net revenues and are committed to pay our proportionate share of additions, replacements and operating and maintenance expenses. As of December 31, 2008, our investment in the Gas Plant included $4.1 million in plant and equipment and $3.6 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. Our share of revenues of the Gas Plant was $4.1 million, $2.8 million and $3.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our share of direct expenses was $0.4 million, $0.3 million and $0.3 million for each of the years ended December 31, 2008, 2007 and 2006. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

(7) LONG-TERM DEBT

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

	2008	2007
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes	(128)	(157)
	224,872	224,843
First mortgage bonds:		
Electric Utilities		
Black Hills Power:		
8.06% due 2010	30,000	30,000
9.49% due 2018	2,810	3,100
9.35% due 2021	21,645	23,310
7.23% due 2032	75,000	75,000
Cheyenne Light:		
6.67% due 2037	110,000	110,000
Industrial development revenue bonds, variable rate, at 3.25% due 2021[(a)]	7,000	7,000
Industrial development revenue bonds, variable rate, at 3.25% due 2027[(a)]	10,000	10,000
	256,455	258,410
Other long-term debt:		
Pollution control revenue bonds at 4.8% due 2014	6,450	6,450
Pollution control revenue bonds at 5.35% due 2024	12,200	12,200
Other	3,353	3,460
	22,003	22,110
Project financing floating rate debt:		
Wygen I project at 5.76% due 2008	—	128,264
Total long-term debt	503,330	633,627
Less current maturities	(2,078)	(130,326)
Net long-term debt	$ 501,252	$ 503,301

(a) Interest rates are presented as of December 31, 2008.

Substantially all of the tangible utility property of Black Hills Power and Cheyenne Light is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of Black Hills Power and Cheyenne Light may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Certain debt instruments of the Company and its subsidiaries contain restrictions and covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2008.

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $2.1 million in 2009, $32.1 million in 2010, $2.1 million in 2011, $2.0 million in 2012, $227.0 million in 2013 and $238.2 million thereafter.

(8) NOTES PAYABLE

Black Hills Corporation had a committed line of credit with various banks totaling $525.0 million and $400.0 million at December 31, 2008 and 2007, respectively. Our $525.0 million credit line is a revolving credit facility, which expires May 4, 2010. The lenders' commitments under this credit facility were increased from $400.0 million to $525.0 million in July 2008. We had $321.0 million of borrowings and $60.7 million of letters of credit and $37.0 million of borrowings and $49.1 million of letters of credit issued under the facility at December 31, 2008 and 2007, respectively. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At our current ratings levels, the facility has an annual facility fee of 17.5 basis points, and has a borrowing spread of 70 basis points over LIBOR (which equates to a 1.14% one-month borrowing rate as of December 31, 2008). We have no compensating balance requirements associated with this credit facility.

At December 31, 2008, Enserco also had a $300.0 million uncommitted, discretionary line of credit to provide support for its purchases of natural gas and crude oil. The line of credit is secured by all of Enserco's assets and expires on May 8, 2009. At December 31, 2008 and 2007, there were outstanding letters of credit issued under the facility of $126.5 million and $197.9 million, respectively, with no borrowing balances on the facility.

In May 2007, we entered into a senior unsecured $1 billion Acquisition Facility with ABN AMRO Bank N.V., as administrative agent, and other banks to fund the Aquila Transaction. In conjunction with the completion of the purchase of the Aquila properties, we executed a single draw of $382.8 million under the Acquisition Facility. The loan was originally scheduled to mature on February 5, 2009. However, on December 18, 2008, we amended the facility to extend the maturity date to December 29, 2009. Borrowings under this facility 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 amended applicable margin for base rate borrowings is 200 basis points and for LIBOR borrowings is 300 basis points, commencing the date of the amendment. Borrowing cost increases 50 basis points each calendar quarter beginning in the second quarter of 2009 until loan maturity. If our credit ratings, as assigned by S&P and Moody's, fall below investment grade, the applicable margin will increase by an additional 25 basis points.

Our credit facilities and debt securities contain certain restrictive financial covenants including, among others, interest expense coverage ratios, recourse leverage ratios and consolidated net worth ratios. At December 31, 2008, we were in compliance with these financial covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

(9) ASSET RETIREMENT OBLIGATIONS

SFAS 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and requires that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. The associated ARO accretion expense is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in the Oil and Gas segment, reclamation of coal mining sites at the Coal Mining segment and removal of fuel tanks, asbestos and transformers containing polychlorinated biphenyls at the Electric Utilities segment and asbestos at our Gas Utilities segment.

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

	Balance at 12/31/07	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/08
Oil and Gas	$ 14,952	$ 5,029	$ (1,213)	$ 855	$ 19,623
Coal Mining	14,778	4,121	(1,839)	639	17,699
Electric Utilities	180	2,381*	—	55	2,616
Gas Utilities	—	213*	—	9	222
Total	$ 29,910	$ 11,744	$ (3,052)	$ 1,558	$ 40,160

* This balance was recorded as part of the purchase price allocation of the Aquila acquisition (see Note 21).

	Balance at 12/31/06	Liabilities Incurred	Liabilities Settled	Accretion	Balance at 12/31/07
Oil and Gas	$ 13,240	$ 1,934	$ (860)	$ 638	$ 14,952
Coal Mining	16,005	233	(1,748)	288	14,778
Electric Utilities	171	—	—	9	180
Total	$ 29,416	$ 2,167	$ (2,608)	$ 935	$ 29,910

We also have legally required asset retirement obligations related to certain assets within our electric and gas utility transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a value for the cost of these obligations cannot be measured at this time.

(10) COMMON STOCK

Private Placement of Common Stock

On February 22, 2007, we completed the issuance and sale of approximately 4.17 million shares of common stock at a price of $36.00 per share in a private placement offering. We used approximately $145.6 million of net proceeds from this offering for debt reduction. On March 31, 2007, the shares were registered for resale under the Securities Act of 1933. At December 31, 2008, the shares are freely tradable by non-affiliates of the Company.

Issuance of Unregistered Securities

On March 21, 2008 and December 19, 2008, the Company issued 451,465 common shares and 142,339 common shares, respectively as additional consideration associated with the Earn-out Litigation described in Note 18. No additional consideration was received in exchange for the earn-out shares.

Equity Compensation Plans

We have several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 878,214 shares available to grant at December 31, 2008.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of SFAS 123(R) and is recognized over the vesting periods of the individual plans. Total stock-based compensation expense for the years ended December 31, 2008, 2007 and 2006 was $1.3 million ($0.9 million, after-tax), $5.8 million ($3.8 million, after-tax) and $2.6 million ($1.7 million, after-tax) respectively, and is included in Administrative and general expense on the accompanying Consolidated Statements of Income. As of December 31, 2008, total unrecognized compensation expense related to stock options and other non-vested stock awards is $5.0 million and is expected to be recognized over a weighted-average period of 2.2 years.

<u>Stock Options</u>

We have granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The options granted vest one-third each year for three years and expire ten years after the grant date.

A summary of the status of the stock option plans at December 31, 2008 is as follows:

	Shares (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Balance at January 1, 2008	539	$ 29.49		
Granted	—	—		
Forfeited/cancelled	(14)	41.67		
Expired	—	—		
Exercised	(90)	25.12		
Balance at December 31, 2008	435	$ 30.01	3.3	$ (1,327)
Exercisable at December 31, 2008	430	$ 29.97	3.2	$ (1,296)

The weighted-average grant-date fair value of options granted during the year ended December 31, 2006 was $3.79. No options were granted for the years ended 2008 and 2007. The total intrinsic value of options (the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option) exercised during the years ended December 31, 2008, 2007 and 2006 was $1.2 million, $1.9 million and $0.8 million, respectively. The total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006 was less than $0.1 million, $0.4 million and $0.6 million, respectively.

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

Valuations Assumptions[1]	2006
Weighted average risk-free interest rate[2]	4.94%
Weighted average expected price volatility[3]	21.54%
Weighted average expected dividend yield[4]	3.98%
Expected life in years[5]	7

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

Net cash received from the exercise of options for the years ended December 31, 2008, 2007 and 2006 was $2.0 million, $4.7 million and $3.7 million, respectively. The tax benefit realized from the exercise of shares granted for the years ended December 31, 2008, 2007 and 2006 was $0.4 million, $0.7 million and $0.3 million, respectively, and was recorded as an increase to equity.

As of December 31, 2008, there was less than $0.1 million of unrecognized compensation expense related to stock options that is expected to be recognized over a weighted-average period of less than one year.

Restricted Stock and Restricted Stock Units

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

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest one-third per year over three years, contingent on continued employment. Compensation cost related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and non-vested restricted stock units at December 31, 2008 is as follows:

	Stock And Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Balance at January 1, 2008	115	$ 36.58
Granted	127	32.39
Vested	(55)	35.43
Forfeited	(15)	38.42
Balance at December 31, 2008	172	$ 33.69

The weighted-average grant-date fair value of restricted stock and restricted stock units granted and the total fair value of shares vested during the years ended December 31, 2008, 2007 and 2006 was as follows:

	Weighted Average Grant Date Fair Value	Total Fair Value of Shares Vested (in thousands)
2008	$ 32.39	$ 2,061
2007	$ 38.67	$ 1,975
2006	$ 35.57	$ 1,332

As of December 31, 2008, there was $4.1 million of unrecognized compensation expense related to non-vested restricted stock and non-vested restricted stock units that is expected to be recognized over a weighted-average period of 2.3 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. In addition, our stock price must also increase during the performance periods.

Participants may earn additional performance shares if the Company's total shareholder return exceeds the 50th percentile of the selected peer group. The final value of the performance shares may vary according to the number of shares of common stock that are ultimately granted based upon the performance criteria.

Outstanding Performance Periods at December 31, 2008 are as follows:

Grant Date	Performance Period	Target Grant of Shares (in thousands)
January 1, 2006	January 1, 2006 – December 31, 2008	26
January 1, 2007	January 1, 2007 – December 31, 2009	29
January 1, 2008	January 1, 2008 – December 31, 2010	28

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is ever determined that a change-in-control is probable, the equity portion of $1.0 million at December 31, 2008 will be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31, 2008 and changes during the twelve-month period ended December 31, 2008, is as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average December 31, 2008 Fair Value
	(in thousands)		(in thousands)	
Balance at January 1, 2008	52	$ 33.43	52	
Granted	16	46.00	16	
Forfeited	(8)	36.20	(8)	
Vested	(18)	33.94	(18)	
Balance at December 31, 2008	42	$ 37.51	42	$ 14.81

The grant date fair value for the performance shares granted in 2008, 2007 and 2006 were determined by Monte Carlo simulation using a blended volatility of 23%, 20% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date. The weighted-average grant-date fair value of performance share awards granted in the years ended December 31, 2008, 2007 and 2006 was as follows:

	Weighted Average Grant Date Fair Value
2008	$ 46.00
2007	$ 34.17
2006	$ 32.06

Performance plan payouts have been as follows:

Performance Period	Year of Payment	Stock Issued	Cash Paid (in thousands)	Total Intrinsic Value
January 1, 2005 to December 31, 2007	2008	35	$ 1,526	$ 3,051
March 1, 2004 to December 31, 2006	2007	4	$ 160	$ 320
March 1, 2004 to December 31, 2005	2006	12	$ 419	$ 837

On January 29, 2009, the Compensation Committee of our Board of Directors determined that the plan criteria for the January 1, 2006 to December 31, 2008 performance period was not met. As a result, there will be no payout for this performance period.

As of December 31, 2008, there was $0.9 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.7 years.

Other Plans

We have a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We have been funding the Plan by the purchase of shares of common stock on the open market since June 2004. At December 31, 2008, 443,976 shares of unissued common stock were available for future offering under the Plan.

We issued 32,568 shares of common stock with an intrinsic value of $1.2 million in the twelve months ended December 31, 2008 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2007. We issued 33,143 and 25,685 shares of common stock in 2007 and 2006, respectively, under the Short-term Annual Incentive Plan.

In addition, we will issue common stock with an intrinsic value of approximately $0.7 million in 2009 for the 2008 Short-term Annual Incentive Plan.

Dividend Restrictions

Our revolving credit facility and Acquisition Facility contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The most restrictive financial covenants include the following: interest expense coverage ratio of not less than 2.5 to 1.0; a recourse leverage ratio not to exceed 0.70 to 1.00 (or 0.65 to 1.00 after the first year of the Aquila acquisition); and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of December 31, 2008, we were in compliance with the above covenants.

Treasury Shares

We acquired 15,107 shares, 767 shares and 6,224 shares of treasury stock related to forfeitures of unvested restricted stock in 2008, 2007 and 2006, respectively, and 17,233 shares, 16,418 shares and 8,095 shares related to the share withholding for the payment of taxes associated with the vesting of restricted shares and stock option exercise stock swaps in 2008, 2007 and 2006, respectively.

We utilized 38,073 shares, 8,030 shares and 46,785 shares of treasury stock in 2008, 2007 and 2006, respectively, related to grants from the different equity plans.

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 168,491	$ 168,491	$ 76,889	$ 76,889
Restricted cash	$ —	$ —	$ 5,443	$ 5,443
Derivative financial instruments – assets	$ 82,867	$ 82,867	$ 38,413	$ 38,413
Derivative financial instruments – liabilities	$ 140,682	$ 140,682	$ 48,755	$ 48,755
Notes payable	$ 703,800	$ 703,800	$ 37,000	$ 37,000
Long – term debt, including current maturities	$ 503,330	$ 456,322	$ 633,627	$ 648,611

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

Cash and Cash Equivalents and Restricted Cash

The carrying amount approximates fair value due to the short maturity of these instruments.

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the various instruments we use and the valuation method employed are included in Note 2.

Notes Payable

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

Long-Term Debt

The fair value of our long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The first mortgage bonds issued by Black Hills Power and Cheyenne Light are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for us to call the bonds.

(12) IMPAIRMENT OF LONG LIVED ASSETS, GOODWILL AND CAPITALIZED DEVELOPMENT COSTS

As a result of low crude oil and natural gas prices at the end of 2008, we recorded a non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment. The lower oil and gas prices at December 31, 2008 resulted in a $91.8 million pre-tax decrease in the full cost accounting method's ceiling limit for capitalized oil and gas property costs. The write-down in the net carrying value of our natural gas and crude oil property was recorded as impairment expense and was based on the December 31, 2008 NYMEX price 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.

In December 2007, the Rupert and Glenns Ferry partnerships, in which we have 50% ownership interests, impaired the carrying amounts of their property, plant and equipment to reflect the partnerships' assessment of the recoverability of their respective carrying amounts. We account for these investments using the equity method of accounting. Accordingly, our carrying amount for these investments was reduced by $3.9 million to reflect the increased losses from the partnerships' impairment charges. In addition, we wrote off $0.6 million of net goodwill impairment directly related to our investments in the partnerships. At December 31, 2007, our remaining carrying amount for these partnership investments was nominal. Our investment in the Rupert and Glenns Ferry partnership is included in the Power Generation segment.

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

(13) OPERATING LEASES

We have entered into lease agreements relating to a compressor lease, vehicle leases and office facility leases. Rental expense incurred under these operating leases was $3.5 million, $0.8 million and $0.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

2009	$	3,703
2010		1,992
2011		1,113
2012		1,002
2013		778
Thereafter		1,726
	$	10,314

(14) INCOME TAXES

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

	2008	2007 (in thousands)	2006
Current:			
Federal	$ (215,957)	$ 22,605	$ 1,573
State	(1,330)	246	(438)
Foreign[1]	1,179	2,114	893
	(216,108)	24,965	2,028
Deferred:			
Federal	185,614	7,405	20,748
State	1,414	349	621
Tax credit amortization	(315)	(292)	(294)
	186,713	7,462	21,075
	$ (29,395)	$ 32,427	$ 23,103

[1]Foreign taxes represent income taxes incurred through our Canadian activities.

The above 2008 amounts reflect the income tax impacts associated with our like-kind exchange tax planning structure. This tax planning structure allowed us to defer approximately $185 million of income taxes related to the IPP Transaction which would have been payable for the 2008 tax year without such a structure.

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

Years ended December 31,	2008	2007
	(in thousands)	
Deferred tax assets, current:		
Asset valuation reserves	$ 2,366	$ 1,609
Mining development and oil exploration	896	373
Unbilled revenue	581	1,480
Deferred costs	—	962
Employee benefits	5,839	3,470
Items of other comprehensive income	1,717	6,606
Derivative fair value adjustments	33,054	250
Other	142	97
	44,595	14,847
Deferred tax liabilities, current:		
Prepaid expenses	2,139	1,890
Derivative fair value adjustments	12,252	1,649
Items of other comprehensive income	6,566	1,601
Deferred costs	10,369	—
Other	3,025	5,195
	34,351	10,335
Net deferred tax asset, current	$ 10,244	$ 4,512
Deferred tax assets, non-current:		
Employee benefits	17,838	14,991
Regulatory liabilities	28,381	5,487
Deferred revenue	591	467
Deferred costs	79	395
State net operating loss	342	1,272
Items of other comprehensive income	15,872	6,400
Foreign tax credit carryover	3,591	3,304
Net operating loss (net of valuation allowance)	7,816	7,846
Asset impairment	32,607	58,819
Derivative fair value adjustment	—	203
Other	8,794	5,703
	115,911	104,887
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	200,119	210,447
Regulatory assets	36,088	13,589
Mining development and oil exploration	94,994	84,771
Deferred costs	352	3,669
Derivative fair value adjustments	221	146
Items of other comprehensive income	4,139	—
Other	3,605	—
	339,518	312,622
Net deferred tax liability, non-current	$ 223,607	$ 207,735
Net deferred tax liability	$ 213,363	$ 203,223

The following table reconciles the change in the net deferred income tax liability from December 31, 2007 to December 31, 2008 to deferred income tax expense:

	2008 (in thousands)
Net change in deferred income tax liability from the preceding table	$ 10,140
Deferred taxes associated with other comprehensive income	(1,773)
Deferred taxes related to net operating loss from acquisitions	2,071
Deferred taxes related to regulatory assets and liabilities	(1,333)
Deferred taxes related to acquisition	13,422
Deferred taxes associated with IPP Transaction	48,131
Deferred taxes associated with property basis differences	114,170
Other	1,885
Deferred income tax expense for the period	$ 186,713

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

	2008	2007	2006
Federal statutory rate	(35.0)%	35.0%	35.0%
State income tax	—	0.4	0.2
Amortization of excess deferred and investment tax credits	(0.4)	(0.4)	(0.7)
Percentage depletion in excess of cost	—	(1.3)	(1.6)
Equity AFUDC	(1.4)	(1.6)	(1.2)
IRS exam tax adjustment*	—	—	(1.8)
State exam tax adjustment**	—	(0.6)	—
Tax credits	—	(0.3)	—
Other	0.8	(1.1)	(0.4)
	(36.0)%	30.1%	29.5%

* As a result of IRS exam settlements for the 2001-2003 tax years, a reduction to income tax expense of approximately $1.4 million was recorded during 2006.

** As a result of state tax exam settlements for the 2001-2003 tax years, a tax benefit of approximately $0.7 million (net of the federal tax effect) was recorded in 2007.

At December 31, 2008, we had the following remaining Net Operating Loss (NOL) carryforwards which were acquired as part of our 2003 acquisition of Mallon Resources Corporation (Mallon):

Net Operating Loss Carryforward (in thousands)	Expiration Year
$ 3,312	2021
17,146	2022
3,104	2023

As of December 31, 2008, we had a valuation allowance of $1.2 million against these NOL carryforwards. Ultimate usage of these NOL's depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOL's, the offsetting amount would affect our financial reporting basis in the acquired Mallon properties.

FIN 48

We adopted the provisions of FIN 48 on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109 and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken. As a result of the implementation of FIN 48, we recognized an approximate $0.7 million benefit from a decrease in the liability for unrecognized tax benefits. This benefit was accounted for as an adjustment to the January 1, 2007 balance of retained earnings.

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

	2008	2007
	(in thousands)	
Beginning balance at December 31	$ 75,770	$ 72,583
Additions for prior year tax positions	5,015	4,719
Reductions for prior year tax positions	(72,948)	(46)
Additions for current year tax positions	112,185	623
Settlements	—	(2,109)
Ending balance at December 31	$ 120,022	$ 75,770

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $4.0 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2008, 2007 and 2006, we recognized approximately $0.5 million, $0.1 million and $0.4 million, respectively of interest. We had approximately $0.4 million and $1.3 million accrued for interest at December 31, 2008 and 2007, respectively.

We file income tax returns with the IRS, various state jurisdictions and Canada. We are currently under examination by the IRS for the 2004, 2005 and 2006 tax years. We remain subject to examination by Canadian income tax authorities for tax years as early as 1999.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statute of limitations prior to December 31, 2009.

In 2005, Canadian income tax returns were filed for the years of 1999 – 2003. Excess foreign tax credits were generated and are available to offset United States federal income taxes. At December 31, 2008, we had the following remaining foreign tax credit carryforwards (in thousands):

	Foreign Tax Credit Carryforward	Expiration Year
$	269	2012
	11	2013
	376	2014
	694	2015
	940	2016
	1,301	2017

(15) COMPREHENSIVE INCOME

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

	2008		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (12,343)	$ 4,331	$ (8,012)
Fair value adjustment of derivatives designated as cash flow hedges	(15,353)	5,224	(10,129)
Reclassification adjustments of cash flow hedges dedesignated and included in net income	42,710	(14,949)	27,761
Reclassification adjustments of cash flow hedges settled and included in net income	(5,992)	2,097	(3,895)
Comprehensive income (loss)	$ 9,022	$ (3,297)	$ 5,725

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

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

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of December 31, 2008	$ (4,522)	$ (14,127)	$ (134)	$ (18,783)
As of December 31, 2007	$ (18,178)	$ (6,115)	$ (215)	$ (24,508)

(16) DISCONTINUED OPERATIONS

We account for discontinued operations under the provisions of SFAS 144. Accordingly, results of operations and the related charges for discontinued operations have been classified as Income (loss) from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as Assets of discontinued operations and Liabilities of discontinued operations. For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

IPP Transaction

On April 29, 2008, we entered into a definitive agreement to sell seven IPP plants to affiliates of Hastings and IIF for $840 million, subject to certain working capital adjustments. The transaction was completed July 11, 2008. Under the agreement, we received net pre-tax cash proceeds of $756 million, including the effects of estimated working capital adjustments and other costs and our required payoff of approximately $67.5 million of associated project level debt. The after-tax gain recorded on the asset sale was approximately $139.7 million. For business segment reporting purposes, results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations associated with the divested IPP plants at December 31 were as follows (in thousands):

	2008	2007	2006
Operating revenues	$ 59,572	$ 121,076	$ 114,297
Pre-tax income from discontinued operations	27,140	38,057	29,483
Gain on sale	233,599	—	—
Income tax expense	(103,758)	(13,214)	(10,699)
Net income from discontinued operations	$ 156,981	$ 24,843	$ 18,784

Allocation of corporate expenses to discontinued operations was made in accordance with SFAS 144 and EITF 87-24. The indirect corporate costs and inter-segment interest expense related to the IPP assets sold and not reclassified to discontinued operations were $11.8 million, $19.0 million and $19.7 million for the years ended 2008, 2007 and 2006, respectively. These allocated costs remain in the Power Generation segment.

Interest expenses included within the operations of the discontinued entities were recorded pursuant to EITF 87-24 and included interest expense on debt which was required to be repaid as a result of the sale transaction. In accordance with EITF 87-24, interest expense was allocated to discontinued operations based on the ratio of the assets sold to total Company net assets, excluding the known debt repayment. For the years ended December 31, 2008, 2007 and 2006, interest expense allocated to discontinued operations was $4.7 million, $11.3 million and $13.6 million, respectively.

Net assets associated with the divested IPP plants were as follows (in thousands):

	December 31, 2007
Current assets	$ 34,112
Property, plant and equipment, net of accumulated depreciation	485,286
Goodwill	18,095
Intangible assets (net of accumulated amortization of $27,363)	21,023
Other non-current assets	13,163
Current liabilities	(15,615)
Long-tem debt	(73,928)
Other non-current liabilities	(139)
Net assets	$ 481,997

Sale of Crude Oil Marketing and Transportation Assets

On January 5, 2006, we entered into an agreement to sell the crude oil marketing and transportation operating assets of BHER. The sale was completed on March 1, 2006. We received approximately $41.0 million of cash proceeds, which was used for debt reduction or other corporate purposes. For business segment reporting purposes, BHER's results were previously included in the Energy Marketing segment.

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

		2006
Operating revenues	$	171,911
Pre-tax loss from discontinued operations	$	(3,018)
Pre-tax gain on sale of assets		13,659
Income tax expense		(3,832)
Net income from discontinued operations	$	6,809

Net assets and financial results for the crude oil marketing and transportation discontinued operations were not significant as of and for the years ended December 31, 2008 and 2007.

(17) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor three 401(k) savings plans. Eligible employees of the Company and its subsidiaries (other than Cheyenne Light and Black Hills Energy) may participate in the Black Hills Corporation Plan. The Cheyenne Light Plan covers eligible employees of Cheyenne Light and the Black Hills Energy Plan covers eligible employees of our utility subsidiaries doing business as Black Hills Energy.

Participants in the Black Hills Corporation Plan may elect to invest up to 100% of their eligible compensation on a pre-tax basis to the Plan up to the maximum amounts established by the IRS. The Black Hills Corporation Plan provides a matching contribution of 100% of the employee's annual tax-deferred contribution up to a maximum of 3% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

Participants in the Cheyenne Light Plan may elect to invest up to 100% of their eligible compensation on a pre-tax or after-tax basis up to maximum amounts established by the IRS. The Cheyenne Light Plan provides for two matching formulas depending on an employee's status as a bargaining unit employee or as a non-bargaining unit employee. Bargaining unit employees receive a maximum match of 5% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 4% of eligible compensation. Non-bargaining unit employees receive a maximum match of 4% of eligible compensation based upon the following formula: 100% of the employee's tax-deferred contribution on the first 3% of eligible compensation, plus 50% of the next 2% of eligible compensation. Matching contributions under both formulas vest immediately. In addition, the Cheyenne Light Plan provides for a profit sharing contribution for certain eligible Cheyenne Light employees equal to 3.5% to 10% of eligible compensation, depending on age and years of service. Profit sharing contributions vest at 20% per year and are fully vested after completion of five years of service.

Participants in the Black Hills Energy Plan, which was established in connection with the Aquila Transaction, may elect to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis up to the maximum amounts established by the IRS. The Black Hills Energy Plan provides a matching contribution of 100% of the employee's annual contribution up to a maximum of 6% of eligible compensation. Matching contributions vest at 20% per year and are fully vested when the participant has five years of service with the Company.

The Black Hills Corporation Plan matching contributions were $2.1 million for 2008, $1.7 million for 2007 and $1.5 million for 2006. The Cheyenne Light Retirement Savings Plan matching contributions were $0.3 million for 2008, $0.3 million for 2007 and $0.2 million for the initial plan year of 2006. The Cheyenne Light Plan profit sharing contributions were $0.1 million for 2008, $0.1 million for 2007 and $0.1 million for 2006. The Black Hills Energy Plan matching contributions were $1.4 million for 2008.

SFAS 158

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

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

SFAS 158 required that the measurement date of plans be the date of our year-end balance sheet. We previously used a September 30 measurement date and during 2008, changed the measurement date to December 31, which resulted in a $1.4 million after-tax adjustment to retained earnings being recognized. The amortization of prior service costs for October 1, 2007 to December 31, 2007 was less than $0.1 million, after-tax, and the service cost, interest cost and expected return on plan assets for October 1, 2007 to December 31, 2007 was $1.3 million, after-tax.

Defined Benefit Pension Plan

We have three non-contributory defined benefit pension plans (the Pension Plans). The Black Hills Corporation Pension Plan covers eligible employees of Black Hills Corporation, Black Hills Service Company, Black Hills Power, WRDC and BHEP. Benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Cheyenne Light Pension Plan covers eligible employees of Cheyenne Light. Benefits for the bargaining unit employees of Cheyenne Light are based on years of service and compensation levels during the highest three consecutive 12-month periods of service, reduced by the vested benefits under the predecessor plans, if any. Benefits for the non-bargaining unit employees of Cheyenne Light are based on annual credits for each year of service plus investment credits. The Black Hills Energy Pension Plan covers eligible employees of our utility subsidiaries doing business as Black Hills Energy. Benefits are based on years of service and compensation levels during the highest four consecutive years of the last ten years of service.

Our funding policy is in accordance with the federal government's funding requirements. The Pension Plans' assets are held in trust and consist primarily of equity and fixed income investments. We use a December 31 measurement date for the Pension Plans.

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

The expected long-term rate of return for equity investments was 9.5% for the 2008 and 2007 plan years. For determining the expected long-term rate of return for equity assets, we reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2008, 8.4%, 11.0%, 9.0% and 9.2%, respectively. Fund management fees were estimated to be 0.18% for S&P 500 Index assets and 0.45% for other assets. The expected long-term rate of return on fixed income investments was 6.0%; the return was based upon historical returns on 10-year treasury bonds of 7.1% from 1962 to 2007, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 4.0%; expected cash returns were estimated to be 2.0% below long-term returns on intermediate-term bonds.

Plan Assets

The percentage of total plan asset fair value by investment category for our Pension Plans at December 31 were as follows:

	2008	2007
Equity	60%	77%
Real estate	5	—
Fixed income	33	21
Cash	2	2
Total	100%	100%

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.

The Black Hills Energy Pension Plan's investment policy includes the investment objective that the achieved long-term rate of return meets or exceeds the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy provides that the Pension Plans will maintain a passive core United States Stock portfolio based on a broad market index. Complementing this core will be investments in United States and foreign equities and fixed income through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Pension Plans may invest, including prohibitions on short sales and the use of options or futures contracts. With regard to pooled funds, the policy requires the evaluation of the appropriateness of such funds for managing Pension Plan assets if a fund engages in such transactions. The Pension Plans have historically not invested in funds engaging in such transactions.

Cash Flows

We made no contributions to the Black Hills Corporation Pension Plan in 2008, but expect to contribute $4.0 million to the Plan in fiscal year 2009. We made a $0.5 million contribution to the Cheyenne Light Pension Plan in the first quarter of 2008 and expect to make a $1.5 million contribution during fiscal year 2009. We expect to make a $13.0 million contribution to the Black Hills Energy Plan in fiscal year 2009.

Supplemental Nonqualified Defined Benefit Retirement Plans

We have various supplemental retirement plans for key executives of the Company. The plans are nonqualified defined benefit plans. We use a December 31 measurement date for the plans.

Plan Assets

The plans have no assets. We fund on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.9 million in 2009. Contributions are expected to be made in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

We sponsor three retiree healthcare plans (the Plans): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company, and the Black Hills Energy Postretirement Healthcare Plan. Employees who participate in the Black Hills Corporation Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits. Employees who participate in the Healthcare Plan for Retirees of Cheyenne Light, Fuel and Power Company and who retire from Cheyenne Light on or after attaining age 55 and after completion of a number of consecutive years of service, which when added to the employee’s age totals 90, are entitled to postretirement healthcare benefits. Employees who are participants in the Black Hills Energy Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service with the Company are entitled to postretirement healthcare benefits.

The benefits for all plans are subject to premiums, deductibles, co-payment provisions and other limitations. We may amend or change the plans periodically. We are not pre-funding the Black Hills Corporation or Cheyenne Light retiree healthcare plans. A portion of Black Hills Energy’s Postretirement Healthcare Plan is pre-funded via Voluntary Employees’ Beneficiary Association (VEBA), and the assets are held in trust. We use a December 31 measurement date for the Plans.

It has been determined that the post-65 retiree prescription drug plans are actuarially equivalent and qualify for the Medicare Part D subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation for the 2008 fiscal year was an actuarial gain of approximately $5.7 million. The effect on 2009 net periodic postretirement benefit cost was a decrease of approximately $0.3 million.

Plan Assets

The Black Hills Corporation and Cheyenne Light retiree healthcare plans have no assets. We fund on a cash basis as benefits are paid. The Black Hills Energy Plan provides for partial pre-funding via VEBA. The assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees of Black Hills Energy located in the states of Kansas and Iowa. We do not pre-fund the Postretirement Healthcare Plan for those employees outside Kansas and Iowa.

Estimated Cash Flows

The estimated employer contribution is expected to be $2.8 million in 2009. Contributions are expected to be made in the form of benefit payments.

The following tables provide a reconciliation of the employee benefit plan obligations and fair value of assets for 2008 and 2007, components of the net periodic expense for the years ended 2008, 2007 and 2006 and elements of accumulated other comprehensive income for 2008 and 2007.

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
	(in thousands)					
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 78,983	$ 77,471	$ 19,943	$ 19,843	$ 13,726	$ 14,042
Sponsorship transfer[(a)]	132,236	—	1,530	—	20,904	—
Service cost	5,474	2,745	559	410	847	539
Interest cost	10,360	4,517	1,588	1,157	1,705	828
Actuarial (gain) loss	21,452	(3,040)	1,123	(737)	1,710	(1,445)
Amendments	20	—	—	—	(768)	—
Benefits paid	(5,980)	(2,710)	(1,881)	(730)	(2,369)	(817)
Medicare Part D accrued	—	—	—	—	81	85
Plan participant's contributions	—	—	—	—	1,104	494
Net increase (decrease)	163,562	1,512	2,919	100	23,214	(316)
Projected benefit obligation at end of year	$ 242,545	$ 78,983	$ 22,862	$ 19,943	$ 36,940	$ 13,726

(a) The sponsorship transfer presents the amount recorded from the change in sponsorship from Aquila to the Company from the Aquila Transaction.

A reconciliation of the fair value of Plan assets (as of the December 31 measurement date) is as follows:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
	(in thousands)					
Beginning market value of plan assets	$ 75,107	$ 65,990	$ —	$ —	$ —	$ —
Acquisition transfer	112,672	—	—	—	4,525	—
Investment income	(45,400)	11,318	—	—	357	—
Contributions	500	510	—	—	1,234	—
Benefits paid	(5,980)	(2,711)	—	—	(1,166)	—
Ending market value of plan assets	$ 136,899	$ 75,107	$ —	$ —	$ 4,950	$ —

Amounts recognized in the statement of financial position consist of:

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans (in thousands)		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
Regulatory asset	$ 70,277	$ 2,998	$ —	$ —	$ 210	$ —
Current liability	$ —	$ —	$ 789	$ 765	$ 1,948	$ 286
Non-current asset	$ —	$ 3,529	$ —	$ —	$ —	$ —
Non-current liability	$ 105,646	$ 7,404	$ 22,073	$ 18,992	$ 30,041	$ 13,386
Regulatory liability	$ —	$ 56	$ —	$ —	$ 1,513	$ 1,682

Accumulated Benefit Obligation

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Accumulated benefit obligation – Black Hills Corporation	$ 68,781	$ 61,513	$ 21,964	$ 14,577	$ 11,547	$ 9,847
Accumulated benefit obligation – Black Hills Energy	$ 131,936	$ —	$ 609	$ —	$ 21,478	$ —
Accumulated benefit obligation – Cheyenne Light	$ 3,212	$ 2,344	$ —	$ —	$ 3,914	$ 3,879

Components of Net Periodic Expense

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
					(in thousands)				
Service cost	$ 4,720	$ 2,745	$ 2,596	$ 447	$ 410	$ 349	$ 721	$ 539	$ 654
Interest cost	9,130	4,517	4,165	1,277	1,157	1,079	1,488	828	813
Expected return on assets	(10,627)	(5,493)	(4,988)	—	—	—	(97)	—	—
Amortization of prior service cost	163	153	153	10	13	13	—	—	(24)
Amortization of transition obligation	—	—	—	—	—	—	59	60	150
Recognized net actuarial loss	—	507	906	569	713	797	(81)	(16)	—
Net periodic expense	$ 3,386	$ 2,429	$ 2,832	$ 2,303	$ 2,293	$ 2,238	$ 2,090	$ 1,411	$ 1,593

Accumulated Other Comprehensive Income

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2008	2007	2008	2007	2008	2007
			(in thousands)			
Net (loss) gain	$ 18,176	$ (1,141)	$ (5,235)	$ (4,967)	$ 9	$ 230
Prior service cost	314	(192)	(3)	(11)	—	—
Transition obligation	—	—	—	—	(21)	(28)
	$ 18,490	$ (1,333)	$ (5,238)	$ (4,978)	$ (12)	$ 202

The amounts in accumulated other comprehensive income, regulatory assets or regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2009 are as follows:

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
		(in thousands)	
Net loss (gain)	$ 1,954	$ 383	$ (21)
Prior service cost	107	—	(58)
Transition obligation	—	—	39
Total net periodic benefit cost expected to be recognized during calendar year 2008	$ 2,061	$ 383	$ (40)

Assumptions

	Defined Benefit Pension Plans			Supplemental Nonqualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
Weighted - average assumptions used to determine benefit obligations:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate	6.20%	6.35%	5.95%	6.20%	6.35%	5.95%	6.10%	6.35%	5.95%
Rate of increase in compensation levels	4.25%	4.34%	4.31%	5.00%	5.00%	5.00%	N/A	N/A	N/A
Weighted - average assumptions used to determine net periodic benefit cost for plan year:	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate:									
Black Hills Corporation	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%	6.35%	5.95%	5.75%
Black Hills Energy	7.00%	N/A	N/A	5.00%	N/A	N/A	6.75%	N/A	N/A
Expected long - term rate of return on assets*	8.50%	8.50%	8.50%	N/A	N/A	N/A	5.00%	N/A	N/A
Rate of increase in compensation levels	4.34%	4.31%	4.34%	N/A	5.00%	5.00%	N/A	N/A	N/A

*The expected rate of return on plan assets remained at 8.5% for the calculation of the 2008 net periodic pension cost.

The healthcare trend rate assumption for 2008 fiscal year benefit obligation determination and 2009 fiscal year expense is a 9% increase for 2009 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013. The healthcare cost trend rate assumption for the 2007 fiscal year benefit obligation determination and 2008 fiscal year expense was a 10% increase for 2008 grading down 1% per year until a 5% ultimate trend rate is reached in fiscal year 2013.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1% increase in the healthcare cost trend assumption would increase the service and interest cost $0.3 million or 14% and the accumulated periodic postretirement benefit obligation $3.4 million or 9%. A 1% decrease would reduce the service and interest cost by $0.3 million or 11% and the accumulated periodic postretirement benefit obligation $2.5 million or 7%.

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

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plan	Non-pension Defined Benefit Postretirement Plans: Expected Gross Benefit Payments	Expected Medicare Part D Drug Benefit Subsidy	Expected Net Benefit Payments
2009	$ 9,616	$ 956	$ 3,328	$ (516)	$ 2,812
2010	10,349	893	3,597	(576)	3,021
2011	11,087	917	3,702	(639)	3,063
2012	11,794	930	3,629	(706)	2,923
2013	12,760	951	3,540	(769)	2,771
2014-2018	80,444	6,872	15,015	(2,493)	12,522

(18) COMMITMENTS AND CONTINGENCIES

Variable Interest Entities

In May 2003, our Black Hills Wyoming subsidiary entered into an agreement with Wygen Funding, Limited Partnership (the VIE) to lease the Wygen I plant. We were considered the "primary beneficiary" of this arrangement and, therefore, 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.

Power Purchase and Transmission Services Agreements

In 1983, we entered into a 40 year power purchase agreement with PacifiCorp providing for our purchase of 75 MW of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduced the contract capacity by 25 MW (5 MW per year starting in 2000) to the current 50 MW of capacity. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $11.6 million in 2008, $10.9 million in 2007 and $10.1 million in 2006.

We have a power purchase agreement with PSCo, expiring in 2011, for 280 MW of capacity and energy in 2009, increasing 10 MW per year to 300 MW in 2011. Pricing for the power purchase agreement is based on annual contracted capacity and an 85% load factor at current FERC approved rates.

We also have a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of our capacity and energy will be transmitted by PacifiCorp: 17 MW in 2004-2006 and 50 MW in 2007-2023. Costs incurred under this agreement were $1.2 million in 2008, $1.2 million in 2007 and $0.4 million in 2006.

Long-Term Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- We have a 10-year power sales contract with MEAN for 20 MW of unit-contingent capacity from the Neil Simpson II plant. The contract expires in 2013.

- During 2008, we had a power sales contract with MEAN for 20 MW of unit-contingent capacity from Wygen I. In January 2009, we completed the sale of a 23.5% ownership interest in Wygen I to MEAN. In conjunction with the sale, the 20 MW power purchase agreement was terminated (see Note 24).

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

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

Reclamation Liability

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land with an equivalent amount added to the asset costs. The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. Approximately $0.6 million, $0.3 million and $0.6 million was charged to accretion expense for the years ended December 31, 2008, 2007 and 2006, respectively. Approximately $0.6 million, $0.5 million and $0.5 million was charged to depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $17.7 million and $14.8 million at December 31, 2008 and 2007, respectively.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in the consolidated financial statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2008, cannot be reasonably determined and could have a material adverse effect on the results of operations or financial position.

Earn-Out Litigation

During 2008, we settled two proceedings brought by former stockholders of Indeck, a company the Company acquired in 2000. The first proceeding, a civil lawsuit, was held in federal court in Illinois. The second proceeding was an arbitration proceeding brought under the terms of a merger agreement that provided for contingent payment of earn-out consideration to the former Indeck stockholders. On March 21, 2008, the parties settled the lawsuit, and on March 27, 2008, the trial court entered an order approving the settlement agreement. Under the settlement agreement, we agreed to pay additional earn-out consideration to the former Indeck stockholders. The aggregate value of the 451,465 shares of additional Black Hills common stock issued was recorded as additional goodwill of $10.9 million.

On September 19, 2008, the arbitrator issued its order in the Company's favor, holding that no earn-out consideration was due by reason of the impairment of the Las Vegas II facility, and its related impact upon the 2003 earn-out payment. The arbitrator, however, instructed us to pay approximately $4.0 million in earn-out consideration that we previously tendered for payment for the 2003 earn-out period. The United States District Judge confirmed this award on December 3, 2008. On December 19, 2008, we issued 142,339 shares of additional common stock to the former Indeck stockholders. We filed a Satisfaction of Judgment in the United States District Court on January 2, 2009. The value of the 142,339 shares of additional Black Hills Common Stock was recorded as additional goodwill. This settlement with the shareholders of Indeck relates to our Power Generation segment, of which we disposed of seven IPP plants. In accordance with SFAS 142, goodwill of this segment was allocated between discontinued operations and continuing operations. Additional goodwill of $3.3 million was recorded in continuing operations in 2008 for the earn-out litigation.

FERC Compliance Investigation

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 have notified the staff of FERC of its findings. We have also evaluated public announcements of civil penalties that have been levied against other companies for violations of FERC regulatory requirements. We believe we have adequately reserved for the estimated potential penalty that could be levied on us. Although the outcome of any legal or regulatory proceedings resulting from these matters cannot be predicted with any certainty, and while the final resolution of these matters could have a material impact on the consolidated net income of any particular period, the outcome of this proceeding is not expected to have a material impact upon our overall consolidated financial position.

(19) GUARANTEES

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

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 of payment 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	

We have guaranteed up to $7.0 million of the obligations of Enserco under an agency agreement whereby Enserco provides services to structure up to $123.5 million United States dollars (converted from $150.0 million Canadian dollars as of December 31, 2008) of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The guarantee expires in July 2009.

We have guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with BP Energy Company and/or BP Canada Energy Marketing Corp. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed up to $20.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with Northern Natural Gas Company. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have has guaranteed up to $25.0 million of the obligations of Black Hills Utility Holdings for payment obligations arising from commodity-related physical and financial transactions with PSCo. These commodity transactions secure natural gas supply for our gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

In addition, at December 31, 2008, we had guarantees in place totaling approximately $6.4 million for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(20) BUSINESS SEGMENTS

Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2008, substantially all of our operations and assets are located within the United States.

Prior to the third quarter of 2008, we managed our business in six reporting segments within two business groups: Utilities and Non-regulated Energy. Utilities consisted of two reporting segments, including the Electric Utility segment (Black Hills Power) and the combination Electric and Gas Utility segment (Cheyenne Light). Non-regulated Energy consisted of four reporting segments, including our Coal Mining, Energy Marketing, Power Generation, and Oil and Gas segments.

In the third quarter of 2008, we changed the reporting segments within our Utilities Group to reflect the significant change to our utility business resulting from the Aquila Transaction (see Note 21). The Utilities Group includes two reporting segments: Electric Utilities and Gas Utilities. We manage our electric and gas utility businesses predominantly by state; however, because our electric utilities and our gas utilities have similar economic characteristics, we aggregate our electric (and combination) utility businesses in the Electric Utilities reporting segment and our gas utility businesses in the Gas Utilities reporting segment. Electric Utilities includes the operating results of the regulated electric utility operations of Black Hills Power and Colorado Electric, and the regulated electric and natural gas utility operations of Cheyenne Light. The natural gas operations within our combination utility, Cheyenne Light, provide stable gross margins and overall financial results. Periodic variances are therefore rarely expected to significantly impact the operating results discussions for the Electric Utilities segment. Presentation of prior periods has been adjusted to reflect the combination of Black Hills Power and Cheyenne Light within the Electric Utilities segment. Gas Utilities, acquired in July 2008, consists of the operating results of the regulated natural gas utility operations of Colorado Gas, Iowa Gas, Kansas Gas, and Nebraska Gas.

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

Utilities Group –

- Electric Utilities, which supplies electric utility service to areas in South Dakota, Wyoming, Montana and Colorado and natural gas utility services to Cheyenne, Wyoming and vicinity; and

- Gas Utilities, which supplies gas utility service to Colorado, Iowa, Kansas and Nebraska. The Gas Utilities were acquired in July 2008 as described in Note 21.

Non-regulated Energy Group –

- Oil and Gas, which produces, explores and operates oil and natural gas interests located in Colorado, Louisiana, Montana, Oklahoma, Nebraska, New Mexico, North Dakota, Wyoming, Texas and California;

- Power Generation, which produces and sells power and capacity to wholesale customers. The power plants are located in Wyoming and Idaho;

- Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and

- Energy Marketing, which markets natural gas, crude oil and related services primarily in the western and central regions of the United States and Canada.

On July 11, 2008, we sold entities that owned seven IPP plants with a total capacity of 974 megawatts. The financial information related to these plants was previously reported in the Power Generation segment and has been reclassified to discontinued operations. Our remaining IPP assets will continue to be reported in the Power Generation segment.

On March 1, 2006, we sold the crude oil marketing and transportation operating assets of BHER and related subsidiaries (see Note 16). The financial information of BHER was previously reported in the Energy Marketing segment and has been reclassified to discontinued operations on the accompanying Consolidated Financial Statements.

December 31:	2008	2007
	(in thousands)	
Total assets		
Utilities:		
Electric Utilities	$ 1,485,040	$ 830,090
Gas Utilities	733,377	—
Non-regulated Energy:		
Oil and Gas	403,583	432,839
Power Generation	155,819	153,120
Coal Mining	75,872	58,024
Energy Marketing	339,543	380,385
Corporate	186,409	42,445
Discontinued operations	246	572,731
Total assets	$ 3,379,889	$ 2,469,634
Capital expenditures and asset acquisitions		
Acquisition costs:		
Payment for acquisition of net assets, net of cash acquired	$ 938,423	$ —
Utilities:		
Electric Utilities	186,237	104,963
Gas Utilities	19,337	—
Non-regulated Energy:		
Oil and Gas	89,169	72,153
Power Generation	5,105	128
Coal Mining	25,190	4,991
Energy Marketing	22	177
Corporate	11,033	22,316
Capital expenditures of continuing operations	1,274,516	204,728
Capital expenditures of discontinued operations	29,836	62,319
Total capital expenditures and asset acquisitions	$ 1,304,352	$ 267,047
Property, plant and equipment		
Utilities:		
Electric Utilities	$ 1,346,836	$ 1,010,925
Gas Utilities	428,279	—
Non-regulated Energy:		
Oil and Gas	648,419	559,394
Power Generation	158,726	155,228
Coal Mining	107,460	86,721
Energy Marketing	2,375	2,389
Corporate	13,397	32,778
Total property, plant and equipment	$ 2,705,492	$ 1,847,435

December 31:	2008	2007	2006
		(in thousands)	
External operating revenues			
Utilities:			
Electric Utilities	$ 472,174	$ 301,514	$ 323,003
Gas Utilities	277,076	—	—
Non-regulated Energy:			
Oil and Gas	106,347	101,522	95,078
Power Generation	38,011	38,658	40,688
Coal Mining	31,842	26,154	22,405
Energy Marketing	59,310	93,836	51,231
Corporate	—	—	46
Total external operating revenues	$ 984,760	$ 561,684	$ 532,451
Intersegment operating revenues			
Utilities:			
Electric Utilities	$ 1,245	$ 1,897	$ 2,352
Non-regulated Energy:			
Power Generation	170	—	—
Coal Mining	25,059	16,334	13,877
Corporate	267	—	—
Intersegment eliminations	(5,711)	(5,077)	(6,095)
Total intersegment operating revenues[(a)]	$ 21,030	$ 13,154	$ 10,134

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

Depreciation, depletion and amortization			
Utilities:			
Electric Utilities	$ 37,648	$ 25,517	$ 25,216
Gas Utilities	14,142	—	—
Non-regulated Energy:			
Oil and Gas	38,549	34,192	30,176
Power Generation	4,627	5,051	5,339
Coal Mining	9,449	5,016	5,211
Energy Marketing	689	813	512
Corporate	2,159	1,178	1,061
Total depreciation, depletion and amortization	$ 107,263	$ 71,767	$ 67,515
Operating income (loss)			
Utilities:			
Electric Utilities	$ 77,866	$ 53,312	$ 45,956
Gas Utilities	14,888	—	—
Non-regulated Energy:			
Oil and Gas	(71,188)	25,437	26,088
Power Generation	14,215	2,596	8,281
Coal Mining	4,293	6,177	6,916
Energy Marketing	30,135	51,769	24,008
Corporate	(13,682)	(13,576)	(8,399)
Intersegment eliminations	(650)	—	(714)
Total operating income	$ 55,877	$ 125,715	$ 102,136

December 31:	2008	2007 (in thousands)	2006
Interest income			
Utilities:			
Electric Utilities	$ 2,041	$ 7,282	$ 3,208
Gas Utilities	376	—	—
Non-regulated Energy:			
Oil and Gas	215	317	156
Power Generation	8,951	20,180	17,969
Coal Mining	1,392	2,074	1,858
Energy Marketing	1,345	3,308	1,859
Corporate	47,425	60,138	61,312
Intersegment eliminations	(59,569)	(89,734)	(84,598)
Total interest income	$ 2,176	$ 3,565	$ 1,764
Interest expense			
Utilities:			
Electric Utilities	$ 25,335	$ 21,012	$ 16,176
Gas Utilities	8,501	—	—
Non-regulated Energy:			
Oil and Gas	5,307	8,974	7,120
Power Generation	20,600	26,098	27,629
Coal Mining	46	390	427
Energy Marketing	1,599	1,177	2,139
Corporate	52,304	57,264	61,053
Intersegment eliminations	(59,569)	(89,734)	(84,598)
Total interest expense	$ 54,123	$ 25,181	$ 29,946
Income taxes			
Utilities:			
Electric Utilities	$ 18,882	$ 12,826	$ 11,607
Gas Utilities	2,447	—	—
Non-regulated Energy:			
Oil and Gas	(26,001)	5,182	7,127
Power Generation	1,683	(2,625)	(2,087)
Coal Mining	2,190	2,091	2,819
Energy Marketing	10,180	19,746	6,419
Corporate	(38,776)	(4,793)	(2,532)
Intersegment eliminations		—	(250)
Total income tax (benefit)/expense	$ (29,395)	$ 32,427	$ 23,103
Income (loss) from continuing operations			
Utilities:			
Electric Utilities	$ 39,674	$ 31,633	$ 24,188
Gas Utilities	4,230	—	—
Non-regulated Energy:			
Oil and Gas	(49,668)	12,706	12,736
Power Generation	3,121	(3,471)	1,117
Coal Mining	4,033	6,107	5,877
Energy Marketing	19,689	34,178	17,322
Corporate	(72,596)	(5,872)	(5,514)
Intersegment eliminations	(650)	—	(464)
Total income (loss) from continuing operations	$ (52,167)	$ 75,281	$ 55,262

(21) ACQUISITIONS

Aquila Transaction

On February 7, 2007, we entered into a definitive agreement with Aquila to acquire its regulated electric utility in Colorado and its regulated gas utilities in Colorado, Kansas, Nebraska and Iowa for $940 million, subject to customary closing adjustments. Based on working capital, capital expenditure and other adjustments, we paid $908.8 million in cash to Aquila and completed the acquisition on July 14, 2008. Additionally, approximately $29.6 million of fees and other costs were capitalized as part of the purchase price. We expect to finalize the purchase price adjustments and allocations in the first half of 2009. The purchase price was financed through our Acquisition Facility and from cash proceeds generated from the IPP Transaction.

This acquisition has been accounted for under the purchase method of accounting, and accordingly, the purchase price has been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. This estimated purchase price allocation is subject to working capital and closing adjustments within one year of the date of acquisition. Allocation of the purchase price (reflecting initial working capital adjustments) is as follows (in thousands):

Current assets	$	113,547
Property, plant and equipment		542,094
Derivative assets		4,695
Goodwill[(a)]		344,460
Intangible assets[(b)]		4,884
Deferred assets		68,134
	$	1,077,814
Current liabilities	$	95,205
Deferred credits and other liabilities		50,224
	$	145,429
Net assets	$	932,385

(a) $247.6 million and $96.9 million of goodwill was allocated to the Electric Utilities and to the Gas Utilities, respectively. All of this goodwill is expected to be fully tax deductible.
(b) Intangible assets include $3.9 million of easements and right–of-ways and $1.0 million of trademark and trade names. This amount is being amortized on a straight-line basis over 20 years.

The following unaudited pro-forma consolidated results of operations have been prepared as if the acquisition of the regulated utilities had occurred on January 1, 2008, 2007 and 2006, respectively (in thousands):

	December 31, 2008	December 31, 2007	December 31, 2006
Operating revenues	$ 1,548,688	$ 1,389,838	$ 1,325,285
Income (loss) from continuing operations	(27,770)	107,712	78,088
Net income	129,477	130,238	103,730
(Loss) earnings per share –			
Basic:			
Continuing operations	$ (0.73)	$ 2.91	$ 2.35
Total	$ 3.39	$ 3.52	$ 3.13
Diluted:			
Continuing operations	$ (0.73)	$ 2.88	$ 2.33
Total	$ 3.39	$ 3.48	$ 3.09

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

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

BHEP has operating and non-operating interests in 1,096 developed oil and gas wells in ten states and holds leases on approximately 416,000 net acres.

Costs Incurred

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

	2008	2007	2006
Acquisition of properties:			
Proved	$ 15,710	$ —	$ 64,265
Unproved	1,290	—	19,336
Exploration costs	13,703	7,250	21,752
Development costs	49,441	62,104	53,080
Asset retirement obligations incurred	5,029	1,934	4,468
	$ 85,173	$ 71,288	$ 162,901

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2008, 2007 and 2006, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Cawley, Gillespie & Associates, Inc., an independent engineering company selected by the Company for 2008 and 2007. Estimates for 2006 are based on reserve reports by Ralph E. Davis Associates, Inc. Such reserve estimates are inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

	2008		2007		2006	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of Bbls of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	5,807	172,964	5,723	164,754	6,835	128,573
Production	(387)	(10,704)	(409)	(11,697)	(401)	(11,512)
Additions – acquisitions	2	3,352	—	—	—	59,813
Additions – extensions and discoveries	438	4,037	373	21,318	118	12,524
Revisions to previous estimates	(675)	(15,217)	120	(1,411)	(829)	(24,644)
Balance at end of year	5,185	154,432	5,807	172,964	5,723	164,754
Proved developed reserves at end of year included above	4,429	88,701	5,095	92,522	4,723	87,891
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

Reserve additions totaled 10.0 Bcfe, replacing 77% of production. The purchase of additional working interests in Wyoming, exploration and development drilling in North Dakota and Wyoming, and detailed reserve work on Montana properties accounted for the majority of the additions. The purchase of additional working interests in Wyoming added 3.8 Bcfe. Drilling in North Dakota (Bakken Shale) and Wyoming (Teapot Sand) accounted for 3.0 Bcfe additions. North Dakota additions were constrained as a result of lease expirations driving drill site selection to lower working interest properties and edge of leasehold where proven undeveloped reserves can only be recognized in one direction. Wyoming bookings were limited by both year-end price and late year completion, limiting opportunity to recognize offset locations. A detailed review of the Montana assets in 2008 resulted in the addition of 2.6 Bcfe in future drilling locations.

The overall revision to reserves totaled 19.2 Bcfe with 78% of this revision, or 15.0 Bcfe, due to lower product prices and higher costs. Performance related revisions were 4.2 Bcfe (less than 2% of year-end 2007 reserve total). We experienced downward revisions in a portion of our San Juan Basin horizontal drilling program and had higher than expected depletion in some Piceance wells. Partially offsetting these downward revisions were positive revisions resulting from our workover program in San Juan Basin that increased production and reserves from existing wells through well clean-up, artificial lift and well-head compression projects.

Capitalized Costs

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

	2008	2007	2006
Unproved oil and gas properties	$ 31,507	$ 37,459	$ 36,936
Proved oil and gas properties	561,779	475,061	409,984
	593,286	512,520	446,920
Accumulated depreciation, depletion & amortization and valuation allowances	(267,893)	(141,780)	(112,020)
Net capitalized costs	$ 325,393	$ 370,740	$ 334,900

Results of Operations

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

	2008	2007	2006
Revenues			
Sales	$ 106,019	$ 101,286	$ 94,682
Production costs	34,198	28,824	27,487
Depreciation, depletion & amortization and valuation provisions*	126,980	31,212	27,420
	161,178	60,036	54,907
Income tax (benefit) expense	(25,925)	5,303	7,180
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ (29,234)	$ 35,947	$ 32,595

* Includes ceiling test adjustment of $91.8 million in 2008.

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure as prescribed in SFAS 69, of discounted future net cash flows and related changes relating to proved oil and gas reserves for the years ended December 31, (in thousands):

	2008	2007	2006
Future cash inflows	$ 875,926	$ 1,544,175	$ 1,238,962
Future production costs	(309,169)	(438,314)	(435,314)
Future development costs	(130,632)	(140,118)	(118,266)
Future income tax expense	(100,791)	(284,678)	(184,373)
Future net cash flows	335,334	681,065	501,009
10% annual discount for estimated timing of cash flows	(156,108)	(358,167)	(233,484)
Standardized measure of discounted future net cash flows	$ 179,226	$ 322,898	$ 267,525

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, (in thousands):

	2008	2007	2006
Standardized measure – beginning of year	$ 322,898	$ 267,525	$ 397,469
Sales and transfers of oil and gas produced, net of production costs	(78,342)	(63,659)	(64,367)
Net changes in prices and production costs	(191,784)	107,920	(233,599)
Extensions, discoveries and improved recovery, less related costs	7,961	34,771	30,114
Net changes in future development costs	26,062	45,127	38,256
Revisions of previous quantity estimates, changes in production rates, changes in timing and other	(41,861)	(71,685)	(106,124)
Accretion of discount	42,485	33,852	56,002
Net change in income taxes	85,218	(30,953)	91,556
Purchases of reserves	6,592	—	58,218
Sales of reserves	(3)	—	—
Standardized measure – end of year	$ 179,226	$ 322,898	$ 267,525

Changes in the standardized measure from “revisions of previous quantity estimates, changes in production rates, changes in timing and other,” are driven by reserve revisions, modifications of production profiles and timing of future development. For both 2008 and 2007, we had minimal net reserve revisions to prior estimates. Production forecast modifications are generally made at the well level each year through the reserve review process. These production profile modifications are based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments are reviewed each year and are often modified in response to current market conditions for items such as permitting, service availability, etc.

(23) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth selected unaudited historical operating results and market data for each quarter of 2008 and 2007. All periods presented are adjusted to reflect the IPP Transaction as Discontinued operations.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2008				
Operating revenues	$ 152,850	$ 153,273	$ 291,892	$ 407,775
Operating income (loss)[a]	25,536	25,523	42,688	(37,870)
Income (loss) from continuing operations [a (b)]	11,739	13,150	19,522	(96,578)
Income (loss) from discontinued operations, net of taxes[c]	5,052	9,046	145,389	(2,240)
Net income (loss) available for common stock	16,791	22,196	164,911	(98,818)
Earnings (loss) per common share:				
Basic -				
Continuing operations	$ 0.31	$ 0.34	$ 0.51	$ (2.52)
Discontinued operations	0.13	0.24	3.79	(0.06)
Total	$ 0.44	$ 0.58	$ 4.30	$ (2.58)
Diluted -				
Continuing operations	$ 0.31	$ 0.34	$ 0.51	$ (2.52)
Discontinued operations	0.13	0.24	3.78	(0.06)
Total	$ 0.44	$ 0.58	$ 4.29	$ (2.58)
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

(a) Includes ceiling test impairment of $91.8 million pre-tax and $59.0 million after-tax in the fourth quarter.
(b) Includes unrealized mark-to-market charge for interest rate swaps of $61.4 million after-tax in the fourth quarter.
(c) Includes gain on the IPP Transaction of $139.7 million after-tax during the third quarter.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2007				
Operating revenues	$ 157,496	$ 133,526	$ 130,168	$ 153,648
Operating income	43,497	31,836	18,392	31,990
Income from continuing operations	26,879	19,489	11,128	17,785
Income from discontinued operations, net of taxes	5,574	5,609	6,336	5,972
Net income available for common stock	32,453	25,098	17,464	23,757
Earnings per common share:				
Basic -				
Continuing operations	$ 0.76	$ 0.52	$ 0.30	$ 0.47
Discontinued operations	0.16	0.15	0.17	0.16
Total	$ 0.92	$ 0.67	$ 0.47	$ 0.63
Diluted -				
Continuing operations	$ 0.75	$ 0.51	$ 0.29	$ 0.47
Discontinued operations	0.16	0.15	0.17	0.15
Total	$ 0.91	$ 0.66	$ 0.46	$ 0.62
Dividends paid per share	$ 0.34	$ 0.34	$ 0.34	$ 0.35
Common stock prices				
High	$ 39.63	$ 42.59	$ 44.48	$ 45.41
Low	$ 35.40	$ 36.86	$ 36.84	$ 40.21

(24) SUBSEQUENT EVENTS

Sale to MEAN

On January 20, 2009, we completed a sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN for $51.0 million. In connection with this sale, we entered into agreements under which MEAN will make payments for costs associated with administrative services, plant operations and coal supplied by our WRDC subsidiary during the life of the facility. Concurrently with this sale, we also terminated a 10-year power purchase contract under which MEAN was obligated to buy 20 MW of power annually from Wygen I.

Guarantees and Surety Bonds

On January 19, 2009, we issued a guarantee for up to $37.9 million to GE Packaged Power, Inc. for payment obligations arising from a purchase contract for a LMS100 gas turbine generator, which is forecasted for use in meeting the needs of our Colorado Electric customers. It is a continuing guarantee which terminates upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated milestone dates with the final payment due September 29, 2010. The purchase contract also gives us a short-term option for the purchase of two additional LMS100 turbine generators at the same pricing as the first generator.

On January 20, 2009, we issued a surety bond for $9.2 million to MEAN to guarantee the payment or reimbursement of operating costs in the Wygen I ownership agreement. Black Hills Wyoming and MEAN entered into the ownership agreement when MEAN acquired a 23.5% ownership interest in the Wygen I plant. The surety bond expires on December 31, 2009.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2008. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Internal control over financial reporting

Management's Report on Internal Control over Financial Reporting is presented on Page 110 of this Annual Report on Form 10-K.

During our fourth fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our directors and information required by Items 401, 405, 407(c)(3), 407(d)(4) and 407 (d)(5) of Regulation S-K is incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 19, 2009.

Our Board of Directors has adopted a Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions. In addition, we have adopted Corporate Governance Guidelines for the Board of Directors, a Code of Business Conduct for our employees and Charters for the Executive, Audit, Compensation and Governance Committees of the Board of Directors. The current version of the documents can be found in the Corporate Governance section of our Web site, *http://www.blackhillscorp.com/corpgov.htm*, and a copy of these materials may be obtained without charge by contacting our Corporate Secretary. We intend to disclose any amendments to, or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and persons performing similar functions, on our Internet website.

Information required by Item 401(b) of Regulation S-K is presented as Item 4A herein as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

ITEM 11. EXECUTIVE COMPENSATION

Information regarding executive compensation and transactions and compensation committee interlocks and insider participation is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 19, 2009.

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

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 19, 2009.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2008 with respect to our equity compensation plans. These plans include the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the 2005 Omnibus Incentive Plan.

Equity Compensation Plan Information			
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders[1]	542,229 [2]	$ 30.01[2]	878,214 [3]
Equity compensation plans not approved by security holders	—	—	—
Total	542,229	$ 30.01	878,214

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

[2] Includes 107,017 full value awards outstanding as of December 31, 2008, comprised of restricted stock units, performance shares and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares or common stock units. In addition, 171,750 shares of unvested restricted stock were outstanding as of December 31, 2008, which are not included in the above table because they have already been issued.

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

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

Information regarding certain relationships and related transactions and director independence is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 19, 2009.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement for the Annual Shareholder's Meeting to be held May 19, 2009.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II.

2. Schedules

Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2008, 2007 and 2006.

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

		Additions				
Description	Balance at Beginning of Year	Adjustments[a]	Charged to Costs and Expenses	Other[b]	Deductions[c]	Balance at End of Year
			(in thousands)			
Allowance for doubtful accounts:						
2008	$ 4,588	$ 3,910	$ 3,262	$ 1,789	$ (6,798)	$ 6,751
2007	4,202	—	2,896	354	(2,864)	4,588
2006	4,685	—	2,811	(5)	(3,289)	4,202

(a) Opening balance of assets acquired in the Aquila Transaction
(b) Recoveries
(c) Uncollectible accounts written off

3. Exhibits

Exhibit Number	Description
2.1*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as Exhibit 2 to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
2.2*	Agreement and Plan of Merger among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp. and Black Hills Corporation dated as of February 6, 2007 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on February 8, 2007).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 30, 2009 (filed as Exhibit 3 to the Registrant's Form 8-K filed February 3, 2009).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002).
10.2†	Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation.
10.3†	2005 Pension Equalization Plan of Black Hills Corporation.
10.4†	2007 Pension Equalization Plan of Black Hills Corporation as Amended and Restated effective January 1, 2009.
10.5†	Restoration Plan of Black Hills Corporation.

10.6†	Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2009.
10.7*†	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant’s Form 10-K for 1997).
10.8*†	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant’s Form 10-K for 2000).
10.9*†	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant’s Form 10-K for 2001).
10.10*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant’s Proxy Statement filed April 13, 2005).
10.11†	First Amendment to the Black Hills Corporation 2005 Omnibus Incentive Plan.
10.12*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on July 11, 2005). Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.11 to the Registrant’s Form 10-K for 2007).
10.13†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.14*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on July 11, 2005). Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.13 to the Registrant’s Form 10-K for 2007).
10.15†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.16*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant’s Form 8-K filed on July 11, 2005). Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.15 to the Registrant’s Form 10-K for 2007).
10.17†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.18*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant’s Form 8-K filed on July 11, 2005). Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.17 to the Registrant’s Form 10-K for 2007).
10.19†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.20*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant’s Form 8-K filed on September 3, 2004).

10.21*†	Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 5, 2008).
10.22*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on June 5, 2008).
10.23†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009.
10.24*†	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1998).
10.25†	First and Second Amendment to the Short-Term Incentive Plan.
10.26*†	Severance and Release Agreement between Mark T. Thies and Black Hills Corporation (filed as Exhibit 10 to the Registrant's Form 8-K filed January 18, 2008).
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23.1	Independent Auditors' Consent.
23.2	Consent of Petroleum Engineer and Geologist.

31.1	Certification of Chief Executive Officer pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a – 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes – Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

(b) See (a) 3. Exhibits above.
(c) See (a) 2. Schedules above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman, President
and Chief Executive Officer

Dated: March 2, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, Chairman, President and Chief Executive Officer	Director and Principal Executive Officer	March 2, 2009
/S/ ANTHONY S. CLEBERG Anthony S. Cleberg, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	March 2, 2009
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 2, 2009
/S/ JACK W. EUGSTER Jack W. Eugster	Director	March 2, 2009
/S/ JOHN R. HOWARD John R. Howard	Director	March 2, 2009
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 2, 2009
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	March 2, 2009
/S/ GARY L. PECHOTA Gary L. Pechota	Director	March 2, 2009
/S/ WARREN L. ROBINSON Warren L. Robinson	Director	March 2, 2009
/S/ JOHN B. VERING John B. Vering	Director	March 2, 2009
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 2, 2009

INDEX TO EXHIBITS

Exhibit Number	Description
2.1*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as Exhibit 2 to the Registrant’s Registration Statement on Form S-4 (No. 333-52664)).
2.2*	Agreement and Plan of Merger among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp. and Black Hills Corporation dated as of February 6, 2007 (filed as Exhibit 2.1 to the Registrant’s Form 8-K filed on February 8, 2007).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3.1 to the Registrant’s Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 30, 2009 (filed as Exhibit 3 to the Registrant’s Form 8-K filed February 3, 2009).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.1 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003).
4.2*	First Supplemental Indenture dated as of May 21, 2003 between the Registrant and LaSalle Bank National Association, as Trustee (filed as Exhibit 4.2 to the Registrant’s Form 10-Q for the quarterly period ended June 30, 2003).
4.3*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as an exhibit to the Registrant’s Registration Statement on Form S-4 (No. 333-52664)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and JPMorgan Chase Bank, as Trustee (filed as Exhibit 10.3 to the Registrant’s Form 10-Q for the quarter ended September 30, 2002).
4.4*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant’s Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant’s Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant’s Form 10-K for 2002).
10.2†	Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation.
10.3†	2005 Pension Equalization Plan of Black Hills Corporation.
10.4†	2007 Pension Equalization Plan of Black Hills Corporation as Amended and Restated effective January 1, 2009.

10.5†	Restoration Plan of Black Hills Corporation.
10.6†	Black Hills Corporation Nonqualified Deferred Compensation Plan as Amended and Restated effective January 1, 2009.
10.7*†	Black Hills Corporation 1996 Stock Option Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1997).
10.8*†	Black Hills Corporation 1999 Stock Option Plan (filed as Exhibit 10.14 to the Registrant's Form 10-K for 2000).
10.9*†	Black Hills Corporation Omnibus Incentive Compensation Plan dated May 30, 2001 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2001).
10.10*†	Black Hills Corporation 2005 Omnibus Incentive Plan (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005).
10.11†	First Amendment to the Black Hills Corporation 2005 Omnibus Incentive Plan.
10.12*†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 11, 2005). Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2007).
10.13†	Form of Stock Option Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.14*†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 11, 2005). Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2007).
10.15†	Form of Restricted Stock Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.16*†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on July 11, 2005). Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2007).
10.17†	Form of Restricted Stock Unit Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.18*†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on July 11, 2005). Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after December 10, 2007 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2007).

10.19†	Form of Performance Share Award Agreement for 2005 Omnibus Incentive Plan effective for awards granted on or after January 1, 2009.
10.20*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.21*†	Change in Control Agreement dated June 1, 2008 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 5, 2008).
10.22*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on June 5, 2008).
10.23†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009.
10.24*†	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1998).
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* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

Exhibit 10.2

Grandfather Amendment
to the
Pension Equalization Plan
of Black Hills Corporation

Pursuant to action taken by the Board of Directors of Black Hills Corporation, Paragraph 1 of the Pension Equalization Plan of Black Hills Corporation ("Plan") is hereby amended to add the following paragraphs, effective January 1, 2005:

Notwithstanding any provision of this Plan to the contrary, the portion of the Plan that applies to the PEP Benefits, as generally defined in paragraph 5, of each employee who was a Participant under this Plan on December 31, 2004 to which the Participant had a legally binding right and whose right to such benefits was earned and vested before January 1, 2005, as determined under Section 409A of the Code and the regulations issued thereunder, shall be treated as "grandfathered" and exempt from the provisions of Section 409A of the Code. Effective October 3, 2004, in no event shall any amendment or other change to the PEP Benefit provisions of this Plan cause a material modification of such provisions, as determined under Section 409A of the Code. Any such amendment or other change shall be void and of no effect.

Effective January 1, 2005, the grandfathered provisions of this Plan, as described above, shall be known as the Grandfathered Pension Equalization Plan of Black Hills Corporation ("Grandfathered PEP").

Effective January 1, 2005, the PEP Benefits, as defined in paragraph 5 of this Plan, of all Participants that are earned or become vested after December 31, 2004 and are not grandfathered, as described above, shall be provided under a separate plan to be known as the 2005 Pension Equalization Plan of Black Hills Corporation ("2005 PEP").

Effective January 1, 2005, the portion of the Plan that applies to the Pension Restoration Benefits, as defined in paragraph 9 of this Plan, of each employee who was a Participant under the Plan as of December 31, 2004 shall be transferred to a separate plan to be known as the Restoration Plan of Black Hills Corporation ("Restoration Plan"). Such Pension Restoration Benefits are not intended to be grandfathered.

In no event shall any amendment made on or after October 3, 2004 to the Restoration Plan, the 2005 PEP, or the Pension Plan of Black Hills Corporation apply to the Grandfathered PEP or to the grandfathered PEP Benefits, as defined above, provided under the provisions of this Plan as in effect on October 3, 2004.

(Signature Page Follows)

Signature Page to Grandfather Amendment to the Pension Equalization Plan
of Black Hills Corporation

BLACK HILLS CORPORATION

By /s/ David R. Emery

David R. Emery
Chairman, President
and Chief Executive Officer

2005 Pension Equalization Plan
of Black Hills Corporation

1. RECITALS

Black Hills Corporation, a South Dakota corporation ("Company") maintains a nonqualified "top hat" plan for certain of its management or highly compensated employees, which was last restated effective the 6th day of November, 2001, known as the Pension Equalization Plan of Black Hills Corporation (the "Original PEP"). The Original PEP provided two types of benefits – a pension equalization or PEP benefit and a restoration benefit.

Effective January 1, 2005, the portion of the Original PEP that provides PEP benefits to each employee who was a Participant under the Original PEP on or before December 31, 2004 to which the Participant had a legally binding right and whose right to such benefits was earned and vested before January 1, 2005, as determined under Section 409A of the Code and the regulations issued thereunder, was treated as "grandfathered" and exempt from the provisions of Section 409A of the Code. Such portion of the Original PEP is known as the "Grandfathered PEP." Effective October 3, 2004, in no event shall any amendment or other change to the Grandfathered PEP cause a material modification of such provisions, as determined under Section 409A of the Code. Any such amendment or other change shall be void and of no effect.

Effective January 1, 2005, the portion of the Original PEP that provides PEP benefits to which Participants did not have a legally binding right or whose right to such benefits was not earned and vested before January 1, 2005 under the Original PEP and which are thus subject to the provisions of Code Section 409A is spun off into this separate plan known as the 2005 Pension Equalization Plan of Black Hills Corporation.

It is the intention of the Company that: (1) this Plan will be operated in reasonable good faith compliance with Code Section 409A and the interim guidance issued thereunder during the period from January 1, 2005 through December 31, 2008; and (2) this Plan will comply with the provisions of Code Section 409A and the final regulations issued thereunder effective January 1, 2009.

2. PURPOSE OF PLAN

The purpose of the Plan is to provide a select group of management or highly compensated employees with certain retirement and death benefits in addition to those benefits which the Participants may enjoy from the Company's tax qualified retirement plans in order to supplement and attempt to equalize total retirement benefits being paid to persons holding like executive and management positions by other companies. The Plan is designed to aid the Company in attracting and retaining its executive employees, persons whose abilities, experience and judgment can contribute to the well-being of the Company. It is the intention of Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees.

3. DEFINITIONS

"Active Participant" shall mean a Participant who has not incurred a Termination of Employment and whose participation hereunder has not been discontinued by the Board of Directors.

"Actuarial Equivalent" shall mean a benefit of equivalent value computed on the basis of the Applicable Interest Rate and the Applicable Mortality Table.

"Affiliate" shall mean any business organization or legal entity that directly or indirectly, controls, is controlled by or is under common control with the Company. For purposes of this definition, the term "control" (including the terms "controlling", "controlled by", and "under common control with") includes the possession, direct or indirect, of the power to vote 50 percent or more of the voting equity securities, membership interest, or other voting interest, or to direct or cause the direction of the management and policies of such business organization or other legal entity, whether through the ownership of voting equity securities, membership interest, by contract, or otherwise.

"Annual Compensation Limitation" shall mean the limitation on annual compensation for tax qualified retirement plans as set forth in Internal Revenue Code Section 401(a)(17) as the same may be amended hereafter from time to time.

“Applicable Interest Rate” shall mean the interest rate (or rates) prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), as in effect for the month of November preceding the first day of the calendar year of distribution.

“Applicable Mortality Table” shall mean (i) in the case of a Participant, the mortality table that is a blend of 75% of the male mortality table and 25% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the Participant and (ii) in the case of a contingent annuitant, the mortality table shall be a blend of 25% of the male mortality table and 75% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the contingent annuitant. If the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e) should be updated to a table that is not based on a blend of underlying male and female mortality tables, then the tables in effect immediately prior to such change shall continue to be used by this Plan without change.

“Average Earnings” shall mean whichever of the following results in the highest annual average Earnings: (i) a Participant’s average Earnings for the five (5) consecutive full calendar years of employment during the ten (10) full calendar years of employment immediately preceding the Calculation Date, which results in the highest such average; or (ii) a Participant’s average Earnings determined by dividing the sum of the following by five (5): (a) the Participant’s Earnings for the four full calendar years preceding the year containing his Calculation Date; (b) the Participant’s Earnings for the year containing his Calculation Date as of the Calculation Date; and (c) a portion of the Participant’s Earnings for the fifth full calendar year preceding the year containing his Calculation Date determined by multiplying his Earnings for said fifth preceding full calendar year by a ratio, the numerator of which shall be 365 minus the number of days in the year containing his Calculation Date measured from the first day of said year to his Calculation Date, and the denominator of which ratio shall be 365. If the Participant has less than five (5) full calendar years of employment, the average shall be taken over his total full calendar years of employment.

“Beneficiary” shall mean the individual or individuals designated by the Participant in accordance with paragraph 7 of the Grandfathered PEP to receive Grandfathered PEP Benefits, if any, which are payable upon the Participant’s death. If no Beneficiary has been designated, or if no Beneficiary survives, the Participant’s remaining 2005 PEP Benefits shall be paid to the estate of the last to survive of the Participant and the Beneficiary.

“Board of Directors” shall mean the Board of Directors of the Company.

“Calculation Date” shall mean the earliest of (i) the date of the Participant’s Termination of Employment, (ii) the date of the Participant’s death and (iii) the date the Participant’s participation in the Plan is discontinued.

“Code” shall mean the Internal Revenue Code of 1986, as amended.

"Controlled Group Member" shall mean any corporation which is a member of a controlled group of corporations (as defined in Section 414(b) of the Code) which includes the Company; any trade or business (whether or not incorporated) which is under common control (as defined in Section 414(c) of the Code) with the Company; any organization (whether or not incorporated) which is a member of an affiliated service group (as defined in Section 414(m) of the Code) which includes the Company; and any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

“Earnings” shall mean the Participant’s Earnings, as defined for purposes of the Pension Plan of Black Hills Corporation but determined without regard to the Annual Compensation Limitation, for a calendar year plus the amount, if any, that the Participant has elected to defer under the Company’s Nonqualified Deferred Compensation Plan for the calendar year.

“Grandfathered PEP” shall have the meaning set out in paragraph 1.

“Grandfathered PEP Benefit” shall mean the PEP Benefit determined under the Grandfathered PEP to which the Participant had a legally binding right and which is earned and vested as of December 31, 2004.

"Key Employee" shall mean a Participant who is a specified employee, as defined as in Code Section 409A and the regulations and other official guidance issued thereunder, and as determined in accordance with procedures established by the Plan Administrator.

"Participant" shall mean an employee or former employee of the Company or an Affiliate who is designated as a Participant pursuant to paragraph 4 and who is or may become entitled to receive benefits under the Plan.

"2005 PEP Benefit" shall mean the benefit payable under the Plan.

"Plan Administrator" shall mean the Pension Administration Committee described in the Pension Plan of Black Hills Corporation.

"Termination of Employment" shall mean separation from service with the Company and all Affiliates, in accordance with the provisions of Code Section 409A. Pursuant to Code Section 409A, unless the facts and circumstances indicate otherwise, a Termination of Employment is presumed to have occurred where the Participant's level of bona fide services performed decreases to a level equal to 20 percent or less of the average level of services performed by the Participant during the immediately preceding 36-month period, and a Termination of Employment will be presumed not to have occurred where the Participant's level of bona fide services performed continues at a level that is 50 percent or more of the average level of service performed by the Participant during the immediately preceding 36-month period. However, a Termination of Employment does not occur while the Participant is on military leave, sick leave, or other bona fide leave of absence if the period of such leave does not exceed six months, or if longer, while the Participant retains a right to reemployment with the Company or any Affiliate under an applicable statute or by contract. A leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate. If the period of leave exceeds six months and the Participant does not retain a right to reemployment under an applicable statute or by contract, the Participant's Termination of Employment is deemed to occur on the day after the end of the six-month period.

"Year of Plan Participation" shall mean each complete twelve-month period beginning on the date an employee becomes a Participant in the Plan and ending at the employee's Termination of Employment or, if earlier, when the employee's participation in the Plan is discontinued by the Board of Directors. Partial years shall be disregarded. No credit for service with the Company or the applicable Affiliate prior to January 1, 1990 shall be given. However, Years of Plan Participation shall include any years of participation credited to the Participant under the Grandfathered PEP prior to January 1, 2005.

4. PARTICIPATION

Any management or highly compensated employees of the Company or its Affiliates whose Salary Level equals or exceeds the Social Security Wage Base and who are designated by the Board of Directors of the Company upon recommendation of the Chief Executive Officer of the Company shall be eligible to participate in the Plan. Each employee of the Company or its Affiliates who was a participant in the Original PEP on December 31, 2004, who remains an employee on January 1, 2005 and whose participation is not discontinued by the Board of Directors before January 1, 2005 shall be a Participant as of January 1, 2005. An employee who was not a Participant on January 1, 2005 will become a Participant on the first day of the calendar month beginning after the date the employee is designated as a Participant by the Board of Directors (or, if later, the participation date specified in the designation). An employee ceases to be an Active Participant upon his Termination of Employment or, if earlier, the date his participation is discontinued by the Board of Directors. If a Participant or former Participant is reemployed by the Company or its Affiliates following a Termination of Employment, such employee will not become an Active Participant again unless he is again designated by the Board of Directors of the Company.

The Board of Directors may in its discretion discontinue the participation of any Participant in the Plan at any time. Such discontinuance shall not reduce the Participant's vested 2005 PEP Benefit, determined as of the date of such discontinuance.

5. 2005 PEP BENEFIT

A Participant's 2005 PEP Benefit shall consist of 180 equal monthly payments, each payment in the amount of one-twelfth of the amount by which (a) exceeds (b), where

(a) Is the product of (i) the Participant's Average Earnings as of the Calculation Date times (ii)(a) 25 percent if the Participant's Average Earnings as of the Calculation Date is less than twice the Social Security Wage Base; or (b) 30 percent if the Participant's Average Earnings as of the Calculation Date equals or exceeds twice the Social Security Wage Base; times (iii) the applicable vesting percentage provided in paragraph 7 as of the Calculation Date; and

(b) Is the Participant's Grandfathered PEP Benefit.

6. COMMENCEMENT OF PAYMENT – AFTER 2008

The provisions of this paragraph 6 shall apply to (i) a Participant whose Termination of Employment occurs after 2004 and before 2009 and who has not attained age 62 by December 31, 2008 and (ii) a Participant whose Termination of Employment occurs after 2008.

(a) General Rules

(1) Payment Commencing During the Participant's Lifetime

Unless a Participant has elected otherwise pursuant to subparagraph 6(b), payment of a Participant's vested 2005 PEP Benefit shall commence within 60 days after the first day of the month following the latest of (i) the date the Participant attains 55 years of age, (ii) the date of the Participant's Termination of Employment, and (iii) January 1, 2009.

If payment of a Participant's vested 2005 PEP Benefit begins before the Participant attains age 62, the vested 2005 PEP Benefit shall be subject to the discount for early commencement described in Schedule 1, attached hereto and incorporated herein by this reference.

Notwithstanding any provision of this Plan to the contrary, if payment of a Key Employee's vested 2005 PEP Benefit is to be made on account of the Key Employee's Termination of Employment, payment to such Key Employee shall begin within 60 days after the later of (1) the first day of the seventh month after the Participant's Termination of Employment or (2) the date otherwise specified herein. If payment is deferred under this paragraph, the first payment of such Participant's 2005 PEP Benefit shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the Applicable Interest Rate.

If the Participant dies after payment of his 2005 PEP Benefit begins, but before all 2005 PEP Benefits have been distributed, the remaining 2005 PEP Benefits shall be paid to his Beneficiary or, if no Beneficiary survives, the remaining monthly 2005 PEP Benefits shall be paid to the estate of the last to survive of the Participant and Beneficiary.

(2) Death of Participant Before Payment Begins

In the event of the Participant's death before payment of his 2005 PEP Benefit begins, the Participant's vested 2005 PEP Benefit shall be paid to the Participant's Beneficiary in 180 equal monthly payments commencing within 60 days after the first day of the month following the date of the Participant's death. The death benefit will not be subject to the discount for early commencement described in Schedule 1 if payment begins before the Participant would have attained age 62.

If no Beneficiary has been designated or if all of the Participant's Beneficiaries die before all 2005 PEP Benefits have been distributed, the remaining 2005 PEP Benefits shall be paid to the estate of the last to survive of the Participant and the Beneficiary.

Neither a Participant nor any Beneficiary can elect to defer payment of benefits under this paragraph 6(a)(2).

(b) Election of Payment Commencement Date

(1) In General

A Participant may elect, in accordance with the provisions of this subparagraph 6(b) and procedures established by the Plan Administrator, to defer payment of his 2005 PEP Benefit beyond the date on which payment would otherwise begin.

(2) Special Transition Election

A Participant who enters the Plan before January 1, 2009 may elect, at any time before December 31, 2008, to have payment of his 2005 PEP Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 6(a)(1).

(3) Initial Election for New Participants

A Participant who enters the Plan on or after January 1, 2009 may elect, at any time during the period beginning on the date he is designated as a Participant and ending 30 days after his Participation begins, to have payment of his 2005 PEP Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 6(a)(1); provided that such Participant shall have no vested interest in his 2005 PEP Benefit until the later of (A) the date the Participant would otherwise become 100% vested in his 2005 PEP Benefit pursuant to the terms of paragraph 7 and (B) the first day of the 14th month following the date he became a Participant.

(4) Re-Deferral Election

A Participant may elect at any time to defer payment of his 2005 PEP Benefit to a specified date that is at least 5 years after the date on which payment would otherwise begin under subparagraph 6(a)(1) or, if later, under an election made pursuant to subparagraph 6(b)(2) or (3); provided that such election will not become effective until 12 months after the date the election is made; and provided further that the election must be made at least 12 months before the date on which payment would otherwise begin.

(c) Special Purpose Distributions

Notwithstanding any provision of this paragraph 6 to the contrary, the Plan Administrator may, in its discretion, distribute a portion of the Participant's vested 2005 PEP Benefit to the extent necessary to:

(1) Satisfy the terms of a domestic relations order, as defined under Code Section 414(p)(1)(B); or

(2) Pay the Participant's share of employment taxes imposed under Code Sections 3101, 3121(a) and 3121(v) on 2005 PEP Benefits (including the income tax at source or state, federal or local income tax withholding due on such distribution).

The Participant's vested 2005 PEP Benefit shall be reduced by the Actuarial Equivalent of the portion of the Participant's vested 2005 PEP Benefit, if any, distributed in accordance with this subparagraph (c).

(d) Small Benefits

Notwithstanding any provision of this paragraph 6 to the contrary, the Plan Administrator may, in its discretion, distribute the lump sum Actuarial Equivalent of the Participant's entire vested 2005 PEP Benefit in a lump sum within 60 days after the Participant's death or Termination of Employment provided that (1) the Participant's entire vested benefit in any other nonqualified non-account balance plan of the Company or any Controlled Group Member that is treated, with this Plan, as a single nonqualified deferred compensation plan under section 1.409A–1(c)(2) of the Income Tax Regulations shall also be paid in a lump sum within 60 days after the Participant's death or Termination of Employment and (2) the total lump sum Actuarial Equivalent of the Participant's vested 2005 PEP Benefit and such other vested benefits does not exceed the applicable dollar amount under Code Section 402(g) (1)(B) (e.g., $15,500 for 2008) for the calendar year in which the distribution is made.

6A. COMMENCEMENT OF PAYMENT – BEFORE 2009

In the case of a Participant whose Termination of Employment occurs after 2004 but before 2009, who attains age 62 before 2009, and who is a Key Employee, payment of his 2005 PEP shall begin within 60 days after the first day of the seventh month after the Participant's Termination of Employment. The first payment of such Participant's 2005 PEP Benefit shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the Applicable Interest Rate.

7. VESTING

Except as otherwise provided herein (including, but not limited to, the provisions of subparagraph 6(b)(3)), a Participant's 2005 PEP Benefit will vest in accordance with the following table:

Years of Plan Participation	Percent of Benefit Vested
Less than 3 years	0%
3 years but less than 4	20%
4 years but less than 5	35%
5 years but less than 6	50%
6 years but less than 7	65%
7 years but less than 8	80%
8 or more years	100%

The provisions for vesting set forth in the paragraph are not intended to give any Participants any rights or claim to any specific assets of the Company.

8. RE-EMPLOYMENT

(a) Former Participant in Another Pension Equalization Plan

If a former Employee who was a Participant in another Pension Equalization Plan maintained by the Company is reemployed and is designated as a Participant of this Plan, his re-employment shall have no impact on the amount, payment, or vested percentage of the Benefit, if any, to which he was entitled under such other Pension Equalization Plan.

His benefit under this Plan shall be equal to (1) minus (2) where

(1) is the 2005 PEP Benefit determined as follows:

(A) using all of his years of Earnings in determining Average Earnings, and

(C) including Years of Plan Participation taken into account under such other Pension Equalization Plan for purposes of determining vesting under this Plan:

(2) is the amount of vested benefit paid or payable to him under such other Pension Equalization Plan as if such benefit had commenced, with appropriate adjustment for early commencement (if needed) and with Actuarial Equivalent adjustment for any difference in the form of payment (if needed), on the same date as his benefit in (1).

(b) Former Participant in This Plan

If a former Participant in this Plan again becomes an employee of the Company or an Affiliate, his re-employment shall have no impact on the amount, payment, or vested percentage of the 2005 PEP Benefit, if any, to which he was entitled at his original Termination of Employment unless the reemployed former Participant is again designated as a Participant under this Plan. If a former Employee who was a Participant in this Plan is again designated as a Participant of this Plan after becoming re-employed by the Company, payment of the 2005 PEP Benefit, if any, to which he was entitled upon his original Termination of Employment shall not be affected. However, the 2005 PEP Benefit, if any, to which he is entitled with respect to his period of re-employment shall be the amount, if any, by which (1) exceeds (2) where

(1) is the 2005 PEP Benefit, determined as follows:

(A) using all of his Years of Plan Participation, and

(B) using all of his years of Earnings in determining Average Earnings; and

(2) is the amount of 2005 PEP Benefit paid or payable to him under this Plan prior to his reemployment as if such benefit had commenced, with appropriate adjustment for early commencement (if needed) and with Actuarial Equivalent adjustment for any difference in the form of payment (if needed), on the same date as his benefit in (1).

9. LOSS OF BENEFITS

Notwithstanding any other provisions in this Plan, if a Participant is terminated on account of misconduct or dishonesty, the Participant shall forfeit all right to any benefit payable under this Plan, including vested accrued benefits.

10. FUNDING OF PLAN

All benefit payments under the Plan will be made from the general assets of the Company. Participants and their beneficiaries who are entitled to be paid benefits under this Plan are unsecured general creditors of the Company. The Company may, but shall not be required to, invest corporate assets in life insurance or annuity contracts to assure that the Company will have a source of funds for the payment of benefits required to be paid under this Plan. Any such insurance or annuity contract shall constitute assets of the Company and the Participant shall have no right, title or interest in any such insurance or annuity contract. The Company reserves the right to refuse participation in the plan to any Participant who, if requested to do so, declines to supply information or to otherwise cooperate as necessary to allow the Company to obtain insurance on the Participant's life.

11. PLAN MAY BE MODIFIED OR DISCONTINUED

The Company reserves the right to amend, modify or discontinue the Plan at any time. Any modification or discontinuance of benefits shall not reduce accrued benefits which become vested prior thereto.

Notwithstanding any provision of the Plan to the contrary, in no event shall the Plan be amended, modified or discontinued in a manner that would have the impact, whether or not intended, of causing the Plan or any Participant in the Plan to violate the provisions of Code Section 409A. Any such amendment, modification or discontinuance shall be void and of no effect.

12. ASSIGNABILITY

Except to the extent permitted under paragraph 6(c)(1), no right to receive payments under this Plan shall be subject to voluntary or involuntary alienation, assignment or transfer.

13. ADMINISTRATION OF THE PLAN

The Plan shall be administered by the Plan Administrator. The Plan Administrator shall have discretionary authority to conclusively interpret the provisions of the Plan, decide all claims, and to make all determinations under the Plan. If the Plan Administrator is a committee, it shall act by vote or written consent of a majority of its members. The Plan Administrator may appoint or employ any agents it deems advisable, including legal and actuarial counsel. When making a determination or calculation, the Plan Administrator shall be entitled to rely upon information furnished by a Participant or Beneficiary, the Company, and the legal and actuarial counsel of the Company. The Plan Administrator may delegate to any person, entity or committee all or any portion of the authority allocated to the Plan Administrator under this Plan. Any such delegation may be revoked at any time. Delegations and revocations thereof shall be in writing.

Notwithstanding any provision of the Plan to the contrary, this Plan shall at all times be administered in compliance with Code Section 409A.

14. CLAIMS PROCEDURE

All claims for benefits under the Plan shall be made to the Plan Administrator. If the Plan Administrator denies a claim, the Plan Administrator shall provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not to exceed an additional 90 days. If the Plan Administrator does not notify the Participant or beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claim shall be written in a manner calculated to be understood by the claimant and shall set forth (1) the specific reason or reasons for the claim denial; (2) specific references to the pertinent Plan provisions on which the denial is based; (3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (4) a description of the Plan's review procedures, including any time limits for such procedures.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Plan Administrator for a full and fair review. The claimant or his duly authorized representative may (1) request a review within the foregoing sixty-(60) day period upon written notice to the Plan Administrator; (2) upon request and free of charge, have reasonable access to and copies of all documents, records, and other information relevant to the claim; and (3) submit written comments, documents, records, and other information relating to the claim for benefits. The foregoing review shall take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

If a claimant fails to request a review within sixty (60) days after receipt of the notice of claim denial, the Plan Administrator's initial determination will be final and binding on all parties.

A decision on the review by the Plan Administrator will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include (1) the specific reason or reasons for the determination on review; (2) reference to the specific plan provisions on which the benefit determination is based; and (3) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits.

The Plan Administrator's determination on review will be final and binding on all parties.

15. <u>WITHHOLDING</u>

There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their beneficiaries, distributees and personal representatives will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

16. <u>GOVERNING LAW</u>

This agreement shall be governed by and construed in accordance with the laws of the State of South Dakota, to the extent not preempted by federal law.

17. <u>NO EMPLOYMENT CONTRACT</u>

Neither the action taken by the Company in establishing the Plan or any action taken by it or by the Plan Administrator under the provisions hereof or any provision of the Plan shall be construed as giving to any eligible Participant the right to be retained in the employment of the Company.

18. NONQUALIFIED AND UNFUNDED PLAN

Notwithstanding anything contained herein, it is intended that this Plan be treated as “nonqualified” and unfunded for tax purposes and for purposes of Title I of ERISA.

19. CHANGE IN CONTROL

In the event of a Change in Control (as defined in a Change in Control Agreement, if any, in effect between a Participant and the Company at the date a Change in Control occurs), the terms of such Change in Control Agreement shall apply with respect to such Participant.

BLACK HILLS CORPORATION

By /s/ David R. Emery

David R. Emery
Chairman, President
and Chief Executive Officer

2005 Pension Equalization Plan
of Black Hills Corporation

SCHEDULE 1

DISCOUNT APPLICABLE TO EARLY COMMENCEMENT

Attained Age at Start of Payments*	Percentage of 2005 PEP Benefit Payable*
61	93.0%
60	86.5%
59	80.5%
58	74.9%
57	69.7%
56	64.8%
55	60.3%

***Note:** The discount shall be adjusted to reflect the number of months, if any, by which payment begins prior to the Participant's next birthday.

2007 Pension Equalization Plan
of Black Hills Corporation
As amended and restated effective January 1, 2009

1. RECITALS

Effective February 2, 2007, Black Hills Corporation, a South Dakota corporation ("Company") established a new "top hat" pension equalization plan for certain of its management or highly compensated employees, to be known as the 2007 Pension Equalization Plan of Black Hills Corporation ("Plan"). Effective January 1, 2009, the Plan is hereby amended and restated in its entirety to reflect changes made to comply with final regulations issued under Internal Revenue Code Section 409A.

It is the intention of the Company that: (1) this Plan will be operated in reasonable good faith compliance with Code Section 409A and the interim guidance issued thereunder during the period from February 2, 2007 through December 31, 2008; and (2) this Plan will comply with the provisions of Code Section 409A and the final regulations issued thereunder effective January 1, 2009.

2. PURPOSE OF PLAN

The purpose of the Plan is to provide a select group of management or highly compensated employees with certain retirement, disability and death benefits in addition to those benefits which the Participants may enjoy from the Company's tax qualified retirement plans in order to supplement and attempt to equalize total retirement benefits being paid to persons holding like executive and management positions by other companies. The Plan is designed to aid the Company in attracting and retaining its executive employees, persons whose abilities, experience and judgment can contribute to the well-being of the Company. It is the intention of Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees.

3. DEFINITIONS

"Active Participant" shall mean a Participant who has not incurred a Termination of Employment and whose participation hereunder has not been discontinued by the Board of Directors.

"Actuarial Equivalent" shall mean a benefit of equivalent value computed on the basis of the Applicable Interest Rate and the Applicable Mortality Table.

"Affiliate" shall mean any business organization or legal entity that directly or indirectly, controls, is controlled by or is under common control with the Company. For purposes of this definition, the term "control" (including the terms "controlling", "controlled by", and "under common control with") includes the possession, direct or indirect, of the power to vote 50 percent or more of the voting equity securities, membership interest, or other voting interest, or to direct or cause the direction of the management and policies of such business organization or other legal entity, whether through the ownership of voting equity securities, membership interest, by contract, or otherwise.

"Annual Compensation Limitation" shall mean the limitation on annual compensation for tax qualified retirement plans as set forth in Internal Revenue Code Section 401(a)(17) as the same may be amended hereafter from time to time.

"Applicable Interest Rate" shall mean the interest rate (or rates) prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), as in effect for the month of November preceding the first day of the calendar year of distribution..

"Applicable Mortality Table" shall mean (i) in the case of a Participant, the mortality table that is a blend of 75% of the male mortality table and 25% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the Participant and (ii) in the case of a contingent annuitant, the mortality table shall be a blend of 25% of the male mortality table and 75% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the contingent annuitant. If the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e) should be updated to a table that is not based on a blend of underlying male and female mortality tables, then the tables in effect immediately prior to such change shall continue to be used by this Plan without change.

"Average Earnings" shall mean whichever of the following results in the highest annual average Earnings: (i) a Participant's average Earnings for the five (5) consecutive full calendar years of employment during the ten (10) full calendar years of employment immediately preceding the Calculation Date, which results in the highest such average; or (ii) a Participant's average Earnings determined by dividing the sum of the following by five (5): (a) the Participant's Earnings for the four full calendar years preceding the year containing his Calculation Date; (b) the Participant's Earnings for the year containing his Calculation Date as of the Calculation Date; and (c) a portion of the Participant's Earnings for the fifth full calendar year preceding the year containing his Calculation Date determined by multiplying his Earnings for said fifth preceding full calendar year by a ratio, the numerator of which shall be 365 minus the number of days in the year containing his Calculation Date measured from the first day of said year to his Calculation Date, and the denominator of which ratio shall be 365. If the Participant has less than five (5) full calendar years of employment, the average shall be taken over his total full calendar years of employment.

"Beneficiary" shall mean the individual(s) designated by the Participant to receive PEP Benefits, if any, which are payable upon the Participant's death. A Participant may name one or more contingent Beneficiaries to receive PEP Benefits in the event any PEP Benefits remain payable after the death of the primary Beneficiary(ies). A Participant's Beneficiary designation must be made in writing and filed with the Plan Administrator on the form provided for that purpose. If more than one Beneficiary designation has been filed, the Beneficiary or Beneficiaries designated in the notice bearing the most recent date will be deemed the valid Beneficiary or Beneficiaries. If no Beneficiary has been designated, or if no Beneficiary survives, the Participant's remaining PEP Benefits shall be paid to the estate of the last to survive of the Participant and the Beneficiary.

"Board of Directors" shall mean the Board of Directors of the Company.

"Calculation Date" shall mean the earliest of (i) the date of the Participant's Termination of Employment, (ii) the date of the Participant's death and (iii) the date the Participant's participation in the Plan is discontinued.

"Code" shall mean the Internal Revenue Code of 1986, as amended.

"Controlled Group Member" shall mean any corporation which is a member of a controlled group of corporations (as defined in Section 414(b) of the Code) which includes the Company; any trade or business (whether or not incorporated) which is under common control (as defined in Section 414(c) of the Code) with the Company; any organization (whether or not incorporated) which is a member of an affiliated service group (as defined in Section 414(m) of the Code) which includes the Company; and any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

“Disability” or “Disabled” shall mean that a Participant (i) is receiving income replacement benefits for at least three months under an employer-sponsored accident and health plan because of any medically determinable physical or mental impairment that is expected to last at least 12 continuous months or result in death, or (ii) has been determined to be total disabled by the Social Security Administration.

“Earnings” shall mean the Participant’s Earnings, as defined for purposes of the Pension Plan of Black Hills Corporation but determined without regard to the Annual Compensation Limitation, for a calendar year plus the amount, if any, of salary, bonus, or other compensation that the Participant has elected to defer under the Company’s Nonqualified Deferred Compensation Plan for the calendar year.

“Key Employee” shall mean a Participant who is a specified employee, as defined as in Code Section 409A and the regulations and other official guidance issued thereunder, and as determined in accordance with procedures established by the Plan Administrator.

“Participant” shall mean an employee or former employee of the Company or an Affiliate who is designated as a Participant pursuant to paragraph 4 and who is or may become entitled to receive benefits under the Plan.

“PEP Benefit” shall mean the benefit payable under the Plan.

“Plan Administrator” shall mean the Pension Administration Committee described in the Pension Plan of Black Hills Corporation.

“Termination of Employment” shall mean separation from service with the Company and all Affiliates, in accordance with the provisions of Code Section 409A. Pursuant to Code Section 409A, unless the facts and circumstances indicate otherwise, a Termination of Employment is presumed to have occurred where the Participant's level of bona fide services performed decreases to a level equal to 20 percent or less of the average level of services performed by the Participant during the immediately preceding 36-month period, and a Termination of Employment will be presumed not to have occurred where the Participant's level of bona fide services performed continues at a level that is 50 percent or more of the average level of service performed by the Participant during the immediately preceding 36-month period. However, a Termination of Employment does not occur while the Participant is on military leave, sick leave, or other bona fide leave of absence if the period of such leave does not exceed six months, or if longer, while the Participant retains a right to reemployment with the Company or any Affiliate under an applicable statute or by contract. A leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate. If the period of leave exceeds six months and the Participant does not retain a right to reemployment under an applicable statute or by contract, the Participant's Termination of Employment is deemed to occur on the day after the end of the six-month period.

“Year of Service as an Officer” shall mean each complete twelve-month period beginning on the date an employee becomes an Officer and ending at the earlier of (i) the date of the employee’s Termination of Employment and (ii) the date the employee ceases to be an Officer. Partial years shall be disregarded.

“Year of Vesting Service” shall mean each complete twelve-month period beginning on the date an employee becomes a Participant in the Plan (or such earlier date specified by the Board of Directors of the Company in its designation of an employee as a Participant in the Plan pursuant to paragraph 4) and ending at the employee’s Termination of Employment or, if earlier, when the employee’s participation in the Plan is discontinued by the Board of Directors. Partial years shall be disregarded.

4. PARTICIPATION

Any management or highly compensated employees of the Company or its Affiliates who are Officers and who are designated by the Board of Directors of the Company upon recommendation of the Chief Executive Officer of the Company shall be eligible to participate in the Plan. Each employee of the Company or its Affiliates who was a participant in the Plan on December 31, 2008, and who remains an employee on January 1, 2009 shall be a Participant as of January 1, 2009. An employee who was not a Participant on December 31, 2008 will become a Participant on the first day of the calendar month beginning after the date the employee is designated as a Participant by the Board of Directors (or, if later, the participation date specified in the designation). An employee ceases to be an Active Participant upon his Termination of Employment or, if earlier, the date his participation is discontinued by the Board of Directors. If a Participant or former Participant is reemployed by the Company or its Affiliates following a Termination of Employment, such employee will not become an Active Participant again unless he is again designated by the Board of Directors of the Company.

The Board of Directors may in its discretion discontinue the participation of any Participant in the Plan at any time. Such discontinuance shall not reduce the Participant's vested PEP Benefit, determined as of the date of such discontinuance.

5. PEP BENEFIT

A Participant's PEP Benefit shall consist of 180 equal monthly payments, each payment in the amount of one-twelfth of the product of (i) 2 percent of the Participant's Average Earnings as of the Calculation Date times (ii) the Participant's Years of Service as an Officer (up to a maximum of 15 years) as of the Calculation Date times (iii) the applicable vesting percentage provided in paragraph 7 as of the Calculation Date.

6. COMMENCEMENT OF PAYMENT

(a) General Rules

(1) Payment Commencing During the Participant's Lifetime

Unless a Participant has elected otherwise pursuant to subparagraph 6(b), payment of a Participant's vested PEP Benefit shall commence within 60 days after the first day of the month following the later of (i) the date the Participant attains 55 years of age or (ii) the date of the Participant's Termination of Employment.

If payment of a Participant's vested PEP Benefit begins before the Participant attains age 62, the vested PEP Benefit shall be subject to the discount for early commencement described in Schedule 1, attached hereto and incorporated herein by this reference.

Notwithstanding any provision of this Plan to the contrary, if payment of a Key Employee's vested PEP Benefit is to be made on account of the Key Employee's Termination of Employment, payment to such Key Employee shall begin within 60 days after the later of (1) the first day of the seventh month after the Participant's Termination of Employment or (2) the date otherwise specified herein. If payment is deferred under this paragraph, the first payment of such Participant's PEP Benefit shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the Applicable Interest Rate.

If the Participant dies after payment of his PEP Benefit begins, but before all PEP Benefits have been distributed, the remaining PEP Benefits shall be paid to his Beneficiary or, if no Beneficiary survives, the remaining PEP Benefits shall be paid to the estate of the last to survive of the Participant and Beneficiary.

(2) <u>Death of Participant Before Payment Begins</u>

Unless a Participant has elected otherwise pursuant to subparagraph 6(b), in the event of the Participant's death before payment of his PEP Benefit begins, monthly payment of the Participant's vested PEP Benefit shall commence within 60 days after the first day of the month following the later of (i) the date the Participant would have attained 55 years of age or (ii) the date of the Participant's death.

If payment of a Participant's vested PEP Benefit begins before the Participant would have attained age 62, the vested PEP Benefit shall be subject to the discount for early commencement described in Schedule 1, attached hereto and incorporated herein by this reference.

If no Beneficiary has been designated or if all of the Participant's Beneficiaries die before all PEP Benefits have been distributed, the remaining PEP Benefits shall be paid to the estate of the last to survive of the Participant and the Beneficiary.

(b) <u>Election of Payment Commencement Date</u>

(1) <u>In General</u>

A Participant may elect, in accordance with the provisions of this subparagraph 6(b) and procedures established by the Plan Administrator, to defer payment of his PEP Benefit beyond the date on which payment would otherwise begin. A Participant may make independent elections with differing deferred commencement dates with respect to benefits commencing due to Termination of Employment or pre-retirement death. An election of the deferral of benefits for one event (Termination of Employment or pre-retirement death) shall not be deemed an election for other event unless specifically so stated.

(2) Initial Election within 30 Days after Participation Begins

A Participant who enters the Plan before January 1, 2009 may elect, at any time during the period beginning on the date he is designated as a Participant and ending 30 days after his Participation begins (but in no event after December 31, 2008), to have payment of his PEP Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 6(a).

Each other Participant may elect, at any time during the period beginning on the date he is designated as a Participant and ending 30 days after his Participation begins, to have payment of his PEP Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 6(a); provided that such Participant shall have no vested interest in his PEP Benefit until the later of (A) the date the Participant would otherwise become 100% vested pursuant to the terms of paragraph 7 and (B) the first day of the 14th month following the date he enters the Plan (unless, prior to the later of such dates, the Participant dies or becomes Disabled while an Active Participant; in which case the PEP Benefit, if any, shall be 100% vested).

(3) Election More than 30 Days after Participation Begins

A Participant may elect at any time to defer payment of his PEP Benefit to a specified date that is at least 5 years after the date on which payment would otherwise begin under subparagraph 6(a) or, if later, under an election made pursuant to subparagraph 6(b)(2); provided that such election will not become effective until 12 months after the date the election is made; and provided further that the election must be made at least 12 months before the date on which payment would otherwise begin.

(c) Special Purpose Distributions

Notwithstanding any provision of this paragraph 6 to the contrary, the Plan Administrator may, in its discretion, distribute a portion of the Participant's vested PEP Benefit to the extent necessary to:

(1) Satisfy the terms of a domestic relations order, as defined under Code Section 414(p)(1)(B); or

(2) Pay the Participant's share of employment taxes imposed under Code Sections 3101, 3121(a) and 3121(v) on PEP Benefits (including the income tax at source or state, federal or local income tax withholding due on such distribution).

The Participant's vested PEP Benefit shall be reduced by the Actuarial Equivalent of the portion of the Participant's vested PEP Benefit, if any, distributed in accordance with this subparagraph (c).

(d) Small Benefits

Notwithstanding any provision of this paragraph 6 to the contrary, the Plan Administrator may, in its discretion, distribute the lump sum Actuarial Equivalent of the Participant's entire vested PEP Benefit in a lump sum within 60 days after the Participant's death or Termination of Employment provided that (1) the Participant's entire vested benefit in any other nonqualified non-account balance plan of the Company or any Controlled Group Member that is treated, with this Plan, as a single nonqualified deferred compensation plan under section 1.409A–1(c)(2) of the Income Tax Regulations shall also be paid in a lump sum within 60 days after the Participant's death or Termination of Employment and (2) the total lump sum Actuarial Equivalent of the Participant's vested PEP Benefit and such other vested benefits does not exceed the applicable dollar amount under Code Section 402(g) (1)(B) (e.g., $15,500 for 2008) for the calendar year in which the distribution is made.

7. VESTING

Except as otherwise provided herein (including, but not limited to, the provisions of subparagraph 6(b)(2)), a Participant's PEP Benefit will vest in accordance with the following table:

If, at Termination of Employment or, if earlier, Discontinuance of Participation, the Participant is	The Participant is entitled to the following percentage of his PEP Benefit
Age 65 or over	100%
Age 55 or over with at least 10 Years of Vesting Service	100%
Age 55 with fewer than 10 Years of Vesting Service	0%
Under age 55	0%

Notwithstanding the foregoing, a Participant's PEP Benefit shall be 100% vested if the Participant dies while an Active Participant or incurs a Termination of Employment while Disabled.

The provisions for vesting set forth in the paragraph are not intended to give any Participants any rights or claim to any specific assets of the Company.

8. <u>DISABILITY</u>

If a Participant becomes Disabled on or after January 1, 2007 and while an Active Participant, and has a Termination of Employment due to such Disability, payment of the Disabled Participant's PEP Benefit shall commence in accordance with paragraph 6.

9. <u>RE-EMPLOYMENT</u>

(a) <u>Former Participant in Another Pension Equalization Plan</u>

If a former Employee who was a Participant in another Pension Equalization Plan maintained by the Company is reemployed and is designated as a Participant of this Plan, his re-employment shall have no impact on the amount, payment, or vested percentage of the Benefit, if any, to which he was entitled under such other Pension Equalization Plan.

His benefit under this 2007 PEP Plan shall be equal to (1) minus (2) where

(1) is the PEP Benefit determined as follows:

(A) using all of his Years of Service as an Officer,

(B) using all of his years of Earnings in determining Average Earnings, and

(C) including years of plan participation taken into account under such other Pension Equalization Plan for purposes of determining vesting under this Plan:

(2) is the amount of the vested benefits paid or payable to him under such other Pension Equalization Plan as if such benefit had commenced, with appropriate adjustment for early commencement (if needed) and with Actuarial Equivalent adjustment for any difference in the form of payment (if needed), on the same date as his benefit in (1).

(b) <u>Former Participant in This Plan</u>

If a former Participant in this Plan again becomes an employee of the Company or an Affiliate, his re-employment shall have no impact on the amount, payment, or vested percentage of the PEP Benefit, if any, to which he was entitled at his original Termination of Employment. If a former Employee who was a Participant in this Plan is again designated as a Participant of this Plan after becoming re-employed by the Company, the PEP Benefit, if any, to which he is entitled with respect to his period of re-employment shall be the amount, if any, by which (1) exceeds (2) where

(1) is the PEP Benefit determined as follows:

(A) using all of his Years of Service as an Officer,

(B) using all of his years of Earnings in determining Average Earnings, and

(C) taking all of his Years of Vesting Service into account for purposes of determining vesting under this Plan; and

(2) is the amount of the vested PEP Benefit paid or payable to him under this Plan prior to his reemployment as if such benefit had commenced, with appropriate adjustment for early commencement (if needed) and with Actuarial Equivalent adjustment for any difference in the form of payment (if needed), on the same date as his benefit in (1).

10. <u>LOSS OF BENEFITS</u>

Notwithstanding any other provisions in this Plan, if a Participant is terminated on account of misconduct or dishonesty, the Participant shall forfeit all right to any benefit payable under this Plan, including vested accrued benefits.

11. <u>FUNDING OF PLAN</u>

All benefit payments under the Plan will be made from the general assets of the Company. Participants and their beneficiaries who are entitled to be paid benefits under this Plan are unsecured general creditors of the Company. The Company may, but shall not be required to, invest corporate assets in life insurance or annuity contracts to assure that the Company will have a source of funds for the payment of benefits required to be paid under this Plan. Any such insurance or annuity contract shall constitute assets of the Company and the Participant shall have no right, title or interest in any such insurance or annuity contract. The Company reserves the right to refuse participation in the plan to any Participant who, if requested to do so, declines to supply information or to otherwise cooperate as necessary to allow the Company to obtain insurance on the Participant’s life.

12. PLAN MAY BE MODIFIED OR DISCONTINUED

The Company reserves the right to amend, modify or discontinue the Plan at any time. Any modification or discontinuance of benefits shall not reduce accrued benefits which become vested prior thereto.

Notwithstanding any provision of the Plan to the contrary, in no event shall the Plan be amended, modified or discontinued in a manner that would have the impact, whether or not intended, of causing the Plan or any Participant in the Plan to violate the provisions of Code Section 409A. Any such amendment, modification or discontinuance shall be void and of no effect.

13. ASSIGNABILITY

Except to the extent permitted under paragraph 6(c)(1), no right to receive payments under this Plan shall be subject to voluntary or involuntary alienation, assignment or transfer.

14. ADMINISTRATION OF THE PLAN

The Plan shall be administered by the Plan Administrator. The Plan Administrator shall have discretionary authority to conclusively interpret the provisions of the Plan, decide all claims, and to make all determinations under the Plan. If the Plan Administrator is a committee, it shall act by vote or written consent of a majority of its members. The Plan Administrator may appoint or employ any agents it deems advisable, including legal and actuarial counsel. When making a determination or calculation, the Plan Administrator shall be entitled to rely upon information furnished by a Participant or Beneficiary, the Company, and the legal or actuarial counsel of the Company. The Plan Administrator may delegate to any person, entity or committee all or any portion of the authority allocated to the Plan Administrator under this Plan. Any such delegation may be revoked at any time. Delegations and revocations thereof shall be in writing.

Notwithstanding any provision of the Plan to the contrary, this Plan shall at all times be administered in compliance with Code Section 409A.

15. CLAIMS PROCEDURE

All claims for benefits under the Plan shall be made to the Plan Administrator. If the Plan Administrator denies a claim, the Plan Administrator shall provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not to exceed an additional 90 days. If the Plan

Administrator does not notify the Participant or beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claim shall be written in a manner calculated to be understood by the claimant and shall set forth (1) the specific reason or reasons for the claim denial; (2) specific references to the pertinent Plan provisions on which the denial is based; (3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (4) a description of the Plan's review procedures, including any time limits for such procedures.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Plan Administrator for a full and fair review. The claimant or his duly authorized representative may (1) request a review within the foregoing sixty-(60) day period upon written notice to the Plan Administrator; (2) upon request and free of charge, have reasonable access to and copies of all documents, records, and other information relevant to the claim; and (3) submit written comments, documents, records, and other information relating to the claim for benefits. The foregoing review shall take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

If a claimant fails to request a review within sixty (60) days after receipt of the notice of claim denial, the Plan Administrator's initial determination will be final and binding on all parties.

A decision on the review by the Plan Administrator will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include (1) the specific reason or reasons for the determination on review; (2) reference to the specific plan provisions on which the benefit determination is based; and (3) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits.

The Plan Administrator's determination on review will be final and binding on all parties.

16. WITHHOLDING

There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their beneficiaries, distributees and personal representatives will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

17. <u>GOVERNING LAW</u>

This agreement shall be governed by and construed in accordance with the laws of the State of South Dakota, to the extent not preempted by federal law.

17. <u>NO EMPLOYMENT CONTRACT</u>

Neither the action taken by the Company in establishing the Plan or any action taken by it or by the Plan Administrator under the provisions hereof or any provision of the Plan shall be construed as giving to any eligible Participant the right to be retained in the employment of the Company.

18. <u>NONQUALIFIED AND UNFUNDED PLAN</u>

Notwithstanding anything contained herein, it is intended that this Plan be treated as "nonqualified" and unfunded for tax purposes and for purposes of Title I of ERISA.

19. <u>CHANGE IN CONTROL</u>

In the event of a Change in Control (as defined in a Change in Control Agreement, if any, in effect between a Participant and the Company at the date a Change in Control occurs), the terms of such Change in Control Agreement shall apply with respect to such Participant.

BLACK HILLS CORPORATION

By <u>/s/ David R. Emery</u>

David R. Emery
Chairman, President
and Chief Executive Officer

2007 Pension Equalization Plan
of Black Hills Corporation
As amended and restated effective January 1, 2009

SCHEDULE 1

DISCOUNT APPLICABLE TO EARLY COMMENCEMENT

Attained Age at Start of Payments*	Percentage of PEP Benefit Payable*
61	93.0%
60	86.5%
59	80.5%
58	74.9%
57	69.7%
56	64.8%
55	60.3%

***Note:** The discount shall be adjusted to reflect the number of months, if any, by which payment begins prior to the Participant's next birthday.

Exhibit 10.5

RESTORATION PLAN OF BLACK HILLS CORPORATION

1. RECITALS

Black Hills Corporation, a South Dakota corporation ("**Company**") maintains a nonqualified "top hat" plan for certain of its management or highly compensated employees, which was last restated effective the 6th day of November, 2001, known as the Pension Equalization Plan of Black Hills Corporation (the "**Original PEP**"). The Original PEP provided two types of benefits – a pension equalization or PEP benefit and a pension restoration benefit.

Effective January 1, 2005, the portion of the Original PEP that provides pension restoration benefits to Participants is spun off into this separate plan known as the Restoration Plan of Black Hills Corporation ("**Plan**"), which provides the pension restoration benefits previously provided under the Original PEP.

The Plan is intended as an unfunded plan to be maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees within the meaning of Sections 201(2), 301(a)(3) and 401(a)(1) of the Employee Retirement Income Security Act of 1974, as amended ("**ERISA**"), and as such it is intended that the Plan be exempt from the participation and vesting, funding, and fiduciary responsibility requirements of Title I of ERISA. The Plan is also intended to qualify for simplified reporting under U.S. Department of Labor Regulation Section 2530.104-23, which provides for an alternative method of compliance for plans described in such regulation. The Plan is not intended to satisfy the qualification requirements of Section 401(a) of the Internal Revenue Code of 1986, as amended (the "**Code**"). The Plan is intended to comply in good faith with the requirements of Code Section 409A and the interim guidance issued thereunder for nonqualified deferred compensation plans during the period from January 1, 2005 through December 31, 2008 and is intended to comply in good faith with the requirements of Code Section 409A and the final regulations issued thereunder for nonqualified deferred compensation plans effective January 1, 2009.

2. PURPOSE OF PLAN

The purpose of the Plan is to provide to a select group of management or highly compensated employees with certain retirement, disability and death benefits which the Participants cannot receive under the Pension Plan of Black Hills Corporation or the Black Hills Utility Holdings, Inc. Pension Plan, as applicable, due to the Code's limits on compensation and annual benefits. The Plan is designed to aid the Company in attracting and retaining its executive employees, persons whose abilities, experience and judgment can contribute to the well-being of the Company. It is the intention of the Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees.

The Plan consists of three Parts: Part I, which contains general provisions applicable to all Participants, Part II, which describes the Restoration Benefits payable to or with respect to Participants whose qualified pension benefits are determined under the Pension Plan of Black Hills Corporation (without regard to whether such benefits are offset by benefits payable under another qualified plan maintained by Black Hills Corporation) and Part III, which describes the Restoration Benefits payable to or with respect to Participants whose qualified pension benefits are determined under the Black Hills Utility Holdings, Inc. Pension Plan (without regard to whether such benefits are offset by benefits payable under another qualified plan maintained by Black Hills Corporation).

PART I

3. DEFINITIONS

The following terms shall apply for purposes of this Plan:

“Active Participant” shall mean a Participant who has not incurred a Termination of Employment and whose participation hereunder has not been discontinued by the Board of Directors.

“Actuarial Equivalent” shall mean a benefit of equivalent value computed on the basis of the Applicable Interest Rate and the Applicable Mortality Table.

“Affiliate” shall mean any business organization or legal entity that directly or indirectly, controls, is controlled by or is under common control with the Company. For purposes of this definition, the term “control” (including the terms “controlling”, “controlled by”, and “under common control with”) includes the possession, direct or indirect, of the power to vote 50 percent or more of the voting equity securities, membership interest, or other voting interest, or to direct or cause the direction of the management and policies of such business organization or other legal entity, whether through the ownership of voting equity securities, membership interest, by contract, or otherwise.

“Annual Compensation Limitation” shall mean the limitation on annual compensation for tax qualified retirement plans as set forth in Internal Revenue Code Section 401(a)(17) as the same may be amended hereafter from time to time.

“Applicable Interest Rate” shall mean the interest rate (or rates) prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), as in effect for the month of November preceding the first day of the calendar year of distribution. Notwithstanding the foregoing, for purposes of determining optional forms of payment for annuity payments commencing after 2004 and before 2008, the Applicable Interest Rate shall mean 6%.

“Applicable Mortality Table” shall mean (i) in the case of a Participant, the mortality table that is a blend of 75% of the male mortality table and 25% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the Participant and (ii) in the case of a contingent annuitant, the mortality table shall be a blend of 25% of the male mortality table and 75% of the female mortality table underlying the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e), regardless of the actual sex of the contingent annuitant. If the mortality table prescribed by the Commissioner of Internal Revenue for purposes of Code Section 417(e) should be updated to a table that is not based on a blend of underlying male and female mortality tables, then the tables in effect immediately prior to such change shall continue to be used by this Plan without change.

“Beneficiary” shall mean, in the case of a Participant who elects to receive payment in the form of a Period Certain Option, the beneficiary designated thereunder.

“Board of Directors” shall mean the Board of Directors of the Company.

“Calculation Date” shall mean the earliest of (i) the date of the Participant’s Termination of Employment, (ii) the date of the Participant’s death and (iii) the date the Participant’s participation in the Plan is discontinued.

“Code” shall mean the Internal Revenue Code of 1986, as amended.

“Contingent Annuity Option” shall mean a reduced monthly benefit payable for the life of the Participant and, if the Participant is survived by his designated contingent annuitant, a monthly benefit equal to one hundred percent (100%), seventy-five percent (75%) or fifty percent (50%) of the monthly benefit payable during the Participant’s lifetime (as elected by the Participant) payable for the life of the contingent annuitant. A Participant whose Restoration Benefit is determined under Part III of the Plan may also elect a Contingent Annuity Option that provides a monthly benefit to the contingent annuitant equal to sixty-six and two-thirds percent (66-2/3%) of the monthly benefit payable during the Participant’s lifetime. The Contingent Annuity Option is the Actuarial Equivalent of the Single Life Annuity. The Participant may not change his designated contingent annuitant after payment begins.

"Controlled Group Member" shall mean any corporation which is a member of a controlled group of corporations (as defined in Section 414(b) of the Code) which includes the Company; any trade or business (whether or not incorporated) which is under common control (as defined in Section 414(c) of the Code) with the Company; any organization (whether or not incorporated) which is a member of an affiliated service group (as defined in Section 414(m) of the Code) which includes the Company; and any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

“Gross Monthly Benefit” or “Gross Monthly Death Benefit” shall mean the benefit determined under the terms of the Pension Plan of Black Hills Corporation or the Black Hills Utility Holdings, Inc. Pension Plan, as applicable, without regard to whether such benefits are offset by benefits payable under another qualified pension plan maintained by Black Hills Corporation.

“Key Employee” shall mean a Participant who is a specified employee, as defined as in Code Section 409A and the regulations and other official guidance issued thereunder, and as determined in accordance with procedures established by the Plan Administrator.

“Participant” shall mean an employee or former employee of the Company or an Affiliate who is designated as a Participant pursuant to Paragraph 4 and who is or may become entitled to receive benefits under the Plan.

“Period Certain Option” shall mean a reduced monthly benefit payable as long as the Participant lives, but guaranteed for a period of 10 years. If the Participant dies before expiration of the guaranteed period certain, payment shall be continued to a designated beneficiary, or, in the absence of a surviving designated beneficiary, the lump sum Actuarial Equivalent of such payments shall be paid to the Participant's estate in a single lump sum. If the designated beneficiary should die while further payments are due, and after having received at least one payment, such further payments shall be made to any person designated by the Participant as an alternate surviving beneficiary or if no such person shall have been designated or survives, the lump sum Actuarial Equivalent of such payments shall be paid to the estate of the surviving beneficiary, in a single lump sum. The Period Certain Option annuity is the Actuarial Equivalent of the Single Life Annuity.

“Plan Administrator” shall mean the Pension Administration Committee described in the Pension Plan of Black Hills Corporation.

“Qualified Joint and Survivor Annuity” shall mean a reduced monthly benefit payable for the life of the Participant and, if the Participant is survived by the Spouse to whom he was married when payment began, a monthly benefit equal to 50% of the monthly benefit payable to the Participant is payable for the life of the surviving Spouse. The Qualified Joint and Survivor Annuity is the Actuarial Equivalent of the Single Life Annuity.

“Restoration Benefit” shall mean, as of any date prior to the date payment under this Plan begins to or with respect to a Participant, the Restoration Benefit determined (1) under the terms of Part II of the Plan if the Participant is currently (or was most recently) an active participant in the Pension Plan of Black Hills Corporation or (2) under the terms of Part III of the Plan if the Participant is currently (or was most recently) an active participant in the Black Hills Utility Holdings, Inc. Pension Plan. If a Participant transfers from active participation in the Pension Plan of Black Hills Corporation to active participation in the Black Hills Utility Holdings, Inc. Pension Plan or vice versa, his Restoration Benefit shall be redetermined under the provisions of this Plan that apply to Participants who are active participants in the qualified plan to which he has transferred and the Restoration Benefit, if any, determined prior to the transfer shall be extinguished. Any election made by the Participant under subparagraph 20(e) shall be deemed to have made under subparagraph 24(e) as well, and any election made by the Participant under subparagraph 24(e) shall be deemed to have been made under Paragraph 20(e) as well. As of the date payment begins to or with respect to a Participant under this Plan, his Restoration Benefit shall mean the Restoration Benefit payable to or with respect to the Participant under Part II of the Plan if the Participant was most recently an active participant in the Pension Plan of Black Hills Corporation or Part III of the Plan if the Participant was most recently an active participant in the Black Hills Utility Holdings, Inc. Pension Plan.

“Single Life Annuity” shall mean a monthly benefit payable for the life of the Participant.

“Spouse” shall mean, in the case of a Restoration Benefit commencing during the Participant’s lifetime, the spouse to whom the Participant is legally married when payment of the Participant’s Restoration Benefit begins and, in the case of a pre-retirement death benefit, the spouse to whom the Participant is legally married during the one-year period ending on the date of the Participant’s death.

“Termination of Employment” shall mean separation from service with the Company and all Affiliates, in accordance with the provisions of Code Section 409A. Pursuant to Code Section 409A, unless the facts and circumstances indicate otherwise, a Termination of Employment is presumed to have occurred where the Participant's level of bona fide services performed decreases to a level equal to 20 percent or less of the average level of services performed by the Participant during the immediately preceding 36-month period, and a Termination of Employment will be presumed not to have occurred where the Participant's level of bona fide services performed continues at a level that is 50 percent or more of the average level of service performed by the Participant during the immediately preceding 36-month period. However, a Termination of Employment does not occur while the Participant is on military leave, sick leave, or other bona fide leave of absence if the period of such leave does not exceed six months, or if longer, while the Participant retains a right to reemployment with the Company or any Affiliate under an applicable statute or by contract. A leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate. If the period of leave exceeds six months and the Participant does not retain a right to reemployment under an applicable statute or by contract, a Termination of Employment is deemed to occur on the day after the end of the six-month period.

4. PARTICIPATION

Management or highly compensated employees of the Company or its Affiliates who are participants in the Pension Plan of Black Hills Corporation or members of the Black Hills Utility Holdings, Inc. Pension Plan and who are designated by the Board of Directors of the Company upon recommendation of the Chief Executive Officer of the Company shall be Participants in the Plan.

Each employee of the Company or its Affiliates who was a Participant in the Plan on December 31, 2004, who remains an employee on January 1, 2005 and whose participation is not discontinued by the Board of Directors before January 1, 2005 shall be a Participant as of January 1, 2005. Each Participant of the Plan who was not actively employed with the Company on December 31, 2004 but who had a vested right to restoration benefits under the Plan shall be a Participant in this Plan as of January 1, 2005 but only with respect to their vested restoration benefit.

An employee who was not a Participant on December 31, 2004 will become a Participant on the first day of the calendar month beginning after the date the employee is designated as a Participant by the Board of Directors (or, if later, the participation date specified in the designation). An employee ceases to be an Active Participant upon his Termination of Employment or, if earlier, the date his participation is discontinued by the Board of Directors. If a Participant or former Participant is reemployed by the Company or its Affiliates following a Termination of Employment, such employee will not become an Active Participant again unless he is again designated by the Board of Directors of the Company.

The Board of Directors may in its discretion discontinue the participation of any Participant in the Plan at any time. Such discontinuance shall not reduce the Participant’s vested Restoration Benefit, determined as of the date of such discontinuance.

5. SPECIAL PURPOSE DISTRIBUTIONS

Notwithstanding any provision of this Plan to the contrary, the Plan Administrator may, in its discretion, distribute a portion of the Participant's vested Restoration Benefit to the extent necessary to:

(a) Satisfy the terms of a domestic relations order, as defined under Code Section 414(p)(1)(B), provided that in no event shall payment under such order be made in a form not otherwise available to i) a Participant under this Plan or ii) an alternate payee, as defined under Code Section 414(p)(8), under the BHC Pension Plan or the BHUH Pension Plan, as applicable; or

(b) Pay the Participant's share of employment taxes imposed under Code Sections 3101, 3121(a) and 3121(v) on Restoration Benefits (including the income tax at source or state, federal or local income tax withholding due on such distribution).

The Participant's vested Restoration Benefit shall be reduced by the Actuarial Equivalent of the portion of the Participant's vested Restoration Benefit, if any, distributed in accordance with this paragraph.

6. SMALL BENEFITS

Notwithstanding any provision of this Plan to the contrary, the Plan Administrator may, in its discretion, distribute the lump sum Actuarial Equivalent of the Participant's entire vested Restoration Benefit within 60 days after the Participant's death or Termination of Employment provided that (1) the Participant's entire vested benefit in any other nonqualified non-account balance plan of the Company or any Controlled Group Member that is treated, with this Plan, as a single nonqualified deferred compensation plan under section 1.409A–1(c)(2) of the Income Tax Regulations shall also be paid in a lump sum within 60 days after the Participant's death or Termination of Employment and (2) the total lump sum Actuarial Equivalent of the Participant's vested Restoration Benefit and such other vested benefits does not exceed the applicable dollar amount under Code Section 402(g) (1)(B) (e.g., $15,500 for 2008) for the calendar year in which the distribution is made.

7. LOSS OF BENEFITS

Notwithstanding any other provisions in this Plan, if a Participant is terminated on account of misconduct or dishonesty, the Participant shall forfeit all right to any benefit payable under this Plan, including vested accrued benefits.

8. FUNDING OF PLAN

All benefit payments under the Plan will be made from the general assets of the Company. Participants and their beneficiaries who are entitled to be paid benefits under this Plan are unsecured general creditors of the Company. The Company may, but shall not be required to, invest corporate assets in life insurance or annuity contracts to assure that the Company will have a source of funds for the payment of benefits required to be paid under this Plan. Any such insurance or annuity contract shall constitute assets of the Company and the Participant shall have no right, title or interest in any such insurance or annuity contract. The Company reserves the right to refuse participation in the plan to any Participant who, if requested to do so, declines to supply information or to otherwise cooperate as necessary to allow the Company to obtain insurance on the Participant’s life.

9. PLAN MAY BE MODIFIED OR DISCONTINUED

The Company reserves the right to amend, modify or discontinue the Plan at any time. Any modification or discontinuance of benefits shall not reduce accrued benefits which become vested prior thereto.

Notwithstanding any provision of the Plan to the contrary, in no event shall the Plan be amended, modified or discontinued in a manner that would have the impact, whether or not intended, of causing the Plan or any Participant in the Plan to violate the provisions of Code Section 409A. Any such amendment, modification or discontinuance shall be void and of no effect.

10. ASSIGNABILITY

Except to the extent permitted under Paragraph 5(a), no right to receive payments under this Plan shall be subject to voluntary or involuntary alienation, assignment or transfer.

11. ADMINISTRATION OF THE PLAN

The Plan shall be administered by the Plan Administrator. The Plan Administrator shall have discretionary authority to conclusively interpret the provisions of the Plan, decide all claims, and to make all determinations under the Plan. If the Plan Administrator is a committee, it shall act by vote or written consent of a majority of its members. The Plan Administrator may appoint or employ any agents it deems advisable, including legal and actuarial counsel. When making a determination or calculation, the Plan Administrator shall be entitled to rely upon information furnished by a Participant, Spouse, or Beneficiary, the Company, and the legal or actuarial counsel of the Company. The Plan Administrator may delegate to any person, entity or committee all or any portion of the authority allocated to the Plan Administrator under this Plan. Any such delegation may be revoked at any time. Delegations and revocations thereof shall be in writing.

Notwithstanding any provision of the Plan to the contrary, this Plan shall at all times be administered in compliance with Code Section 409A.

12. CLAIMS PROCEDURE

All claims for benefits under the Plan shall be made to the Plan Administrator. If the Plan Administrator denies a claim, the Plan Administrator shall provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not to exceed an additional 90 days. If the Plan Administrator does not notify the Participant or beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claim shall be written in a manner calculated to be understood by the claimant and shall set forth (1) the specific reason or reasons for the claim denial; (2) specific references to the pertinent Plan provisions on which the denial is based; (3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (4) a description of the Plan's review procedures, including any time limits for such procedures.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Plan Administrator for a full and fair review. The claimant or his duly authorized representative may (1) request a review within the foregoing sixty-(60) day period upon written notice to the Plan Administrator; (2) upon request and free of charge, have reasonable access to and copies of all documents, records, and other information relevant to the claim; and (3) submit written comments, documents, records, and other information relating to the claim for benefits. The foregoing review shall take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

If a claimant fails to request a review within sixty (60) days after receipt of the notice of claim denial, the Plan Administrator's initial determination will be final and binding on all parties.

A decision on the review by the Plan Administrator will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include (1) the specific reason or reasons for the determination on review; (2) reference to the specific plan provisions on which the benefit determination is based; and (3) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits.

The Plan Administrator's determination on review will be final and binding on all parties.

13. WITHHOLDING

There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their beneficiaries, distributees and personal representatives will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

14. GOVERNING LAW

This agreement shall be governed by and construed in accordance with the laws of the state of South Dakota, to the extent not preempted by federal law.

15. NO EMPLOYMENT CONTRACT

Neither the action taken by the Company in establishing the Plan or any action taken by it or by the Plan Administrator under the provisions hereof or any provision of the Plan shall be construed as giving to any eligible Participant the right to be retained in the employment of the Company.

16. NONQUALIFIED AND UNFUNDED PLAN

Notwithstanding anything contained herein, it is intended that this Plan be treated as “nonqualified” and unfunded for tax purposes and for purposes of Title I of ERISA.

17. CHANGE IN CONTROL

In the event of a Change in Control (as defined in a Change in Control Agreement, if any, in effect between a Participant and the Company at the date a Change in Control occurs), the terms of such Change in Control Agreement shall apply with respect to such Participant.

PART II

18. DEFINITIONS

Except as otherwise provided herein, the terms used in Part II of the Plan shall have the meaning assigned to them under the BHC Pension Plan. In addition, the following terms shall apply for purposes of this Plan:

"Average Restoration Earnings" shall mean the average of the Participant’s Restoration Earnings determined using the same rules, methods and procedures used to determine Average Monthly Earnings under the BHC Pension Plan.

"Average Monthly Restoration Earnings" shall mean an amount equal to 1/12 of a Participant's Average Restoration Earnings.

“BHC Pension Plan” shall mean the Pension Plan of Black Hills Corporation, as in effect as of the Calculation Date.

“Dependent Child” shall mean a legitimately born or legally adopted child of the Participant who has not attained age 18.

“Disability” or “Disabled” shall mean that a Participant is absent from employment with the Company because of a disability that makes him eligible for benefits under the Company's long term disability plan. Disability ends when the Participant ceases to be eligible for benefits under the Company’s long term disability plan.

“Disabled Participant” shall mean a Participant who became Disabled while an Active Participant and who continues to accrue benefits under the terms of the BHC Pension Plan. A Participant shall cease to be a Disabled Participant when he ceases to be eligible for benefits under the Company’s long term disability plan.

“Normal Retirement Date” shall mean the last day of the month in which the Participant attains age 65.

"Restoration Earnings" shall mean the Participant’s Earnings, as defined for purposes of the BHC Pension Plan but determined without regard to the Annual Compensation Limitation, for a calendar year plus the amount, if any, by which (i) exceeds (ii), where (i) is the amount of salary, bonus, or other compensation that the Participant has elected to defer under the Company’s Nonqualified Deferred Compensation Plan for the calendar year and (ii) is the amount, if any, by which (A) exceeds (B), where (A) is the Annual Compensation Limitation for the calendar year and (B) is the Participant’s Earnings under the BHC Pension Plan for the calendar year.

“Section 415 Benefit Limitation” shall mean the limitation on the provision of annual benefits as set out in the BHC Pension Plan.

19. RETIREMENT BENEFITS - PARTICIPANTS WHOSE BHC PENSION PLAN BENEFITS COMMENCE AFTER 2004 AND BEFORE JANUARY 1, 2009

If payment of a Participant’s BHC Pension Plan benefit begins on or after January 1, 2005 and before January 1, 2009, then the Participant shall be entitled to receive a Restoration Benefit equal to the amount, if any, by which (a) exceeds (b), where;

(a) is the monthly benefit that would have been provided to the Participant under the BHC Pension Plan calculated using the Participant’s Average Monthly Restoration Earnings and determined without regard to the Section 415 Benefit Limitation; and

(b) is the actual monthly benefit provided to the Participant under the BHC Pension Plan.

The Restoration Benefit shall be payable at like times and in like manner as the BHC Pension Plan benefit, provided that Restoration Benefits becoming payable to a Key Employee on account of such Key Employee’s Termination of Employment shall be delayed in accordance with the provisions of the second paragraph of subparagraph 20(b).

Notwithstanding anything contained above, in the event that a Participant hereunder is not a participant in or eligible to participate in the BHC Pension Plan, then such Participant shall have no right to any Restoration Benefit under this paragraph, and nothing contained herein shall be deemed to provide for or suggest the right in any Participant hereunder to be a participant or be eligible to participate in the BHC Pension Plan.

20. RETIREMENT BENEFITS - PARTICIPANTS WHOSE BHC PENSION PLAN BENEFITS COMMENCE ON OR AFTER JANUARY 1, 2009

(a) Amount of Benefit – Participants Other than Disabled Participants. If payment of a Participant’s BHC Pension Plan benefit does not begin before January 1, 2009, the Participant’s Restoration Benefit shall be the amount, determined as of the Calculation Date, by which (1) exceeds (2), where:

(1) is the Gross Monthly Benefit payable as a Single Life Annuity which would have been provided to the Participant under the BHC Pension Plan commencing at the Participant's Normal Retirement Date, calculated using the Participant's Average Monthly Restoration Earnings and determined without regard to the Section 415 Benefit Limitation; and

(2) is the Gross Monthly Benefit payable as a Single Life Annuity to the Participant under the BHC Pension Plan commencing at the Participant's Normal Retirement Date.

If payment of the Restoration Benefit begins before the Participant's Normal Retirement Date, the benefit will be reduced for early commencement using (i) the early retirement reduction factors specified in Section 4.2 of the BHC Pension Plan or (ii) the deferred vested factors specified in Section 5.1 of the BHC Pension Plan, as applicable.

(b) Amount of Benefit – Disabled Participants. The Restoration Benefit payable to a Participant who is a Disabled Participant on the later of (i) the date he attains age 55 and (ii) the date of his Termination of Employment will be equal to the amount, if any, by which (1) exceeds (2), where:

(1) is the Gross Monthly Benefit payable as a Single Life Annuity which would have been provided to the Participant under Section 4.7 of the BHC Pension Plan commencing on the first day of the month following the Participant's Normal Retirement Date, calculated using the Participant's Average Monthly Restoration Earnings and the number of years of Credited Service that he would have had if he had remained Disabled until his Normal Retirement Date, and determined without regard to the Section 415 Benefit Limitation; and

(2) is the actual Gross Monthly Benefit payable as a Single Life Annuity to the Participant under Section 4.7 of the BHC Pension Plan commencing on the first day of the month following the Participant's Normal Retirement Date.

If payment of the Restoration Benefit begins before the Participant's Normal Retirement Date, the benefit will be reduced for early commencement using (i) the early retirement reduction factors specified in Section 4.2 of the BHC Pension Plan or (ii) the deferred vested factors specified in Section 5.1 of the BHC Pension Plan, as applicable.

(c) Time of Payment. Unless otherwise elected under subparagraph 20(e), payment of the Restoration Benefit shall commence within 60 days after the first day of the month following the later of (i) the date the Participant attains 55 years of age or (ii) the date of the Participant's Termination of Employment. Notwithstanding the foregoing, in the case of a Participant whose Termination of Employment occurred before January 1, 2009 and who has not elected otherwise under subparagraph 20(e), payment of the Restoration Benefit shall commence within 60 days after the first day of the month following the later of (i) the date the Participant attains 55 years of age and (ii) January 1, 2009.

Notwithstanding any provision of this Plan to the contrary, if payment of a Key Employee's vested Restoration Benefit is to be made on account of the Key Employee's Termination of Employment, payment to such Key Employee shall begin within 60 days after the later of (1) the first day of the seventh month after the Participant's Termination of Employment or (2) the date otherwise specified herein. If payment is deferred under this paragraph, the first payment of such Participant's Restoration Benefit shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the Applicable Interest Rate.

(d) Form of Payment. The Participant may elect, at any time before payment begins, to receive payment of his Restoration Benefit in the form of a Single Life Annuity, a Qualified Joint and Survivor Annuity, a Contingent Annuity Option or a Period Certain Option. Such election shall be made in writing in accordance with procedures established by the Plan Administrator. If a Participant fails to elect a form of payment, payment shall be made as a Single Life Annuity if the Participant is unmarried when payment begins or a Qualified Joint and Survivor Annuity if the Participant is married when payment begins. A Participant may not change the form of payment after payment begins.

(e) Optional Elections as to Time of Payment. A Participant may elect, in accordance with the provisions of this subparagraph 20(e) and procedures established by the Plan Administrator, to defer payment of his Restoration Benefit payable under this Paragraph 20 beyond the date on which payment would otherwise begin, provided that such election shall not apply to pre-retirement death benefits under this Plan. Any election made under this subparagraph 20(e) shall also apply if the Participant's Restoration Benefit is payable under Paragraph 24 instead of this Paragraph 20.

(1) Initial Election. A Participant who enters the Plan before January 1, 2009 and whose benefits do not commence before January 1, 2009 may elect, at any time before December 31, 2008, to have payment of his Restoration Benefit commence on the later of Termination of Employment or a specified date (or attainment of a specified age) that is after the date the Participant attains age 55**.** Each other Participant may elect, at any time during the period beginning on the date he is designated as a Participant and ending 30 days after his Participation begins, to have payment of his Restoration Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 20(c); provided that such Participant shall have no vested interest in his Restoration Benefit until the later of (A) the date the Participant would otherwise become 100% vested pursuant to the terms of Paragraph 22 and (B) the first day of the 14th month following the date he enters the Plan (unless, prior to the later of such dates, a Participant who otherwise meets the conditions for 100% vesting pursuant to Paragraph 22 dies or becomes disabled (as defined for purposes of Code Section 409A), in which case the Restoration Benefit, if any, shall be 100% vested).

(2) Subsequent Election. A Participant may elect at any time to defer payment of his Restoration Benefit to a specified date that is at least 5 years after the date on which payment would otherwise begin under subparagraph

20(d) or, if later, under an election made pursuant to subparagraph 20(e)(1); provided that such election will not become effective until 12 months after the date the election is made; and provided further that the election must be made at least 12 months before the date on which payment would otherwise begin.

21. PRE-RETIREMENT DEATH BENEFITS

The provisions of this Paragraph 21 describe the death benefits, if any, payable with respect to a Participant who dies before payment of his Restoration Benefits begins.

(a) Death Before Age 55 as an Active or Disabled Participant.

(1) Amount of Benefit. If the Participant dies before age 55 as an Active Participant or a Disabled Participant and if payment of any death benefits due with respect to the Participant under the BHC Pension Plan has not begun by January 1, 2009, then the Participant's surviving Spouse or Dependent Children, as applicable, shall be entitled to receive a Restoration Death Benefit, which first payment shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit that would have been provided under Section 5.4(a) of the BHC Pension Plan, commencing on the first day of the month following the Participant's death, if the benefit payable before the Participant's 55th birthday had been calculated using the Participant's Restoration Earnings and the benefit payable after the Participant's 55th birthday had been calculated using the Participant's Restoration Earnings or the Participant's Average Monthly Restoration Earnings, as applicable, and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under Section 5.4(a) of the BHC Pension Plan, commencing on the first day of the month following the Participant's death.

The amount of each monthly payment after this first payment shall not change for any reason, including the remarriage of the Spouse.

(2) Time of Payment and Form of Payment. Payment of the death benefit described in (1) above will be paid monthly. Payment will commence within 60 days after the first day of the month following the later of (i) the date of the Participant's death or (ii) January 1, 2009. The last payment will be due on the first day of the month in which the last of the following occurs:

(A) The death of the surviving Spouse;

(B) The 18th birthday of the last living Dependent Child of the Participant; or

(C) The death of the last Dependent Child of the Participant who has not attained age eighteen (18).

If there is no surviving Spouse or if the surviving Spouse is not living on the due date of any monthly payment of the survivor benefit, such monthly payment shall be divided in equal shares and paid to the Dependent Child or Dependent Children of the Participant who are surviving and have not attained age 18 on such date.

(b) Death at or after Age 55 as an Active or Disabled Participant.

(1) Amount of Benefit. If the Participant dies at or after age 55 as an Active Participant or a Disabled Participant and if payment of any death benefits due with respect to the Participant under the BHC Pension Plan has not begun by January 1, 2009, then the Participant's surviving Spouse or Dependent Children, as applicable, shall be entitled to receive a Restoration Death Benefit, which first payment shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit which would have been provided under Section 5.4 (b) of the BHC Pension Plan, as applicable, commencing on the first day of the month following the Participant's death, if such benefit had been calculated using the Participant's Restoration Earnings or the Participant's Average Monthly Restoration Earnings, as applicable, and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under Section 5.4(b) of the BHC Pension Plan, commencing on the first day of the month following the Participant's death, or, in the case of a Disabled Participant who dies after payment of his benefit begins under the BHC Pension Plan but before his Normal Retirement Date, the Gross Monthly Death Benefit that would have been payable under Section 5.4(b) of the BHC Pension Plan, commencing on the first day of the month following the Participant's death, if he had not elected to begin payment of his benefit under the BHC Pension Plan before his death.

The amount of each monthly payment after this first payment shall not change for any reason, including the remarriage of the Spouse.

(2) Time of Payment and Form of Payment. Payment of the death benefit described in (1) above will be made monthly. Payment will commence within 60 days after the first day of the month following the later of (i) the

date of the Participant's death or (ii) January 1, 2009. The last payment will be due on the first day of the month in which the last of the following occurs:

(A) The death of the surviving Spouse;

(B) The 18th birthday of the last living Dependent Child of the Participant; or

(C) The death of the last Dependent Child of the Participant who has not attained age 18.

If there is no surviving Spouse or if the surviving Spouse is not living on the due date of any monthly payment of the survivor benefit, such monthly payment shall be divided in equal shares and paid to the Dependent Child or Dependent Children of the Participant who are surviving and have not attained age 18 on such date.

(c) Death after Termination of Employment.

(1) Amount of Benefit. If a Participant who has a vested right to his Restoration Benefit dies at a time when he is not an Active Participant or a Disabled Participant, and if payment of any death benefits due under the BHC Pension Plan has not begun by January 1, 2009, then the Participant's surviving Spouse shall be entitled to receive a Restoration Benefit, which shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit which would have been provided under Section 5.4(c) of the BHC Pension Plan commencing on the first day of the month following the later of (1) the Participant's death or (2) the date the Participant would have attaine age 55, if such benefit had been calculated using the Participant's Average Monthly Restoration Earnings and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under the BHC Pension Plan commencing on the first day of the month following the later of (1) the Participant's death or (2) the date the Participant would have attained age 55.

If payment begins before the date the Participant would have attained age 55, the Plan benefit will be the Actuarial Equivalent of the benefit commencing at the date the Participant would have attained age 55. The last payment of the monthly death benefit will be due on the first day of the month in which the death of the surviving Spouse occurs.

(2) Time of Payment and Form of Payment. Payment of the monthly death benefit described in (1) will commence within 60 days after the first day of the month beginning after the later of (i) the date of the Participant's death or (ii) January 1, 2009. If payment begins after the date the Participant would have attained age 55 but before the Participant's Normal Retirement Date, the Plan benefit will be reduced for early commencement, if applicable, under the terms of the BHC Pension Plan.

22. VESTING

Except as otherwise provided herein (including, but not limited to, the provisions of subparagraph 20(e)(1)), a Participant's Restoration Benefit will vest only in accordance with the following table:

Years of Vesting Service	Percent of Benefit Vested
Less than 5 years	0
5 or more years	100

Notwithstanding the foregoing, a Participant's Restoration Benefit shall be 100% vested if the Participant is an Active Participant or Disabled Participant on his 65th birthday or, if earlier, the date of his death.

The provisions for vesting set forth in this paragraph are not intended to give any Participants any right or claim to any specific assets of the Company.

PART III

23. DEFINITIONS

Except as otherwise provided herein, the terms used in Part III of the Plan shall have the meaning assigned to them under the BHUH Pension Plan. In addition, the following terms shall apply for purposes of this Plan:

"Average Monthly Restoration Earnings" shall mean the average of the Participant's Monthly Restoration Earnings determined using the same rules, methods and procedures used to determine Average Monthly Earnings under the BHUH Pension Plan.

"BHUH Pension Plan" shall mean the Black Hills Utility Holdings, Inc. Pension Plan, as in effect as of the Calculation Date.

"Disability" or "Disabled" shall mean that a Participant has been determined to be totally disabled by the Social Security Administration. Disability ends when the Social Security Administration determines that the Participant is no longer totally disabled.

“Disabled Participant” shall mean a Participant who had at least 5 years of Service and was an Active Participant when he became Disabled. Disability ends when the Social Security Administration determines that the Participant is no longer totally disabled.

“Final Average Restoration Pay” shall mean means the average of the Participant’s Total Monthly Restoration Pay determined using the same rules, methods and procedures used to determine Final Average Pay under the BHUH Pension Plan.

“Monthly Restoration Earnings” shall mean Monthly Earnings, as defined for purposes of the BHUH Pension Plan but determined without regard to the Annual Compensation Limitation, for a calendar year plus the amount, if any, by which (i) exceeds (ii), where (i) is the amount of salary, bonus, or other compensation that the Participant has elected to defer under the Company’s Nonqualified Deferred Compensation Plan for the calendar year and (ii) is the amount, if any, by which (A) exceeds (B), where (A) is the Annual Compensation Limitation for the calendar year and (B) is the Participant’s Monthly Earnings under the BHUH Pension Plan for the calendar year.

“Normal Retirement Date” shall mean the first day of the month coinciding with or next following the Participant’s 62nd birthday.

"Total Monthly Restoration Pay" shall mean the Participant’s Total Monthly Pay, as defined for purposes of the BHUH Pension Plan, for a calendar year plus the amount, if any, by which (i) exceeds (ii), where (i) is the amount of salary, bonus, or other compensation that the Participant has elected to defer under the Company’s Nonqualified Deferred Compensation Plan for the calendar year and (ii) is the amount, if any, by which (A) exceeds (B), where (A) is the Annual Compensation Limitation for the calendar year and (B) is the Participant’s Total Monthly Pay under the BHUH Pension Plan for the calendar year.

“Section 415 Benefit Limitation” shall mean the limitation on the provision of annual benefits as set out in the BHUH Pension Plan.

24. RETIREMENT BENEFITS

(a) Amount of Benefit – Participants Other Than Disabled Participants. The Participant’s Restoration Benefit shall be the amount, determined as of the Calculation Date, by which (1) exceeds (2), where:

(1) is the Gross Monthly Benefit payable as a Single Life Annuity that would have been provided to the Participant under the BHUH Pension Plan commencing at the Participant’s Normal Retirement Date, calculated using the Participant’s Final Average Restoration Pay or Average Monthly Restoration Earnings, as applicable, and determined without regard to the Section 415 Benefit Limitation; and

(2) is the actual Gross Monthly Benefit payable as a Single Life Annuity to the Participant under the BHUH Pension Plan commencing at the Participant’s Normal Retirement Date.

If payment of the Restoration Benefit begins before the Participant's Normal Retirement Date, the benefit will be reduced for early commencement using (A) the early retirement reduction factors specified in Section 4.03 of the BHUH Pension Plan or (B) the deferred vested factors specified in Section 6.01 of the BHUH Pension Plan, as applicable.

(b) Amount of Benefit – Disabled Participants. In the case of a Participant who is a Disabled Participant on the later of (i) the date he attains age 55 and (ii) the date of his Termination of Employment will be equal to the amount determined as of the Calculation Date, if any, by which (1) exceeds (2), where:

(1) is the Gross Monthly Benefit payable as a Single Life Annuity that would have been provided to the Participant under the BHUH Pension Plan commencing at the Participant's Normal Retirement Date, calculated using (A) the Participant's Final Average Restoration Pay or Average Monthly Restoration Earnings, as applicable, determined as of his Termination of Employment due to Disability and (B) the number of years of Credited Service or Years of GA 106 Service, as applicable, that the Participant would have had if he had remained in active service as a Participant until his Normal Retirement Date and determined without regard to the Section 415 Benefit Limitation; and

(2) is the actual Gross Monthly Benefit payable as a Single Life Annuity to the Participant under the BHUH Pension Plan commencing at the Participant's Normal Retirement Date.

If payment of the Restoration Benefit begins before the Participant's Normal Retirement Date, the benefit will be reduced for early commencement using (A) the early retirement reduction factors specified in Section 4.03 of the BHUH Pension Plan or (B) the deferred vested factors specified in Section 6.01 of the BHUH Pension Plan, as applicable.

(c) Time of Payment. Unless otherwise elected under subparagraph 24(d) payment shall begin within 60 days after the first day of the month following the later of (A) the date the Participant attains 55 years of age or (B) the date of the Participant's Termination of Employment.

If payment to a Participant who is a Key Employee is to be made on account of the Participant's Termination of Employment, payment of such Participant's Restoration Benefit shall commence within 60 days after the later of (1) the first day of the seventh month after the Participant's Termination of Employment or (2) the date otherwise specified herein. If payment is deferred under this paragraph, the first payment of such Participant's Restoration Benefit shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the Applicable Interest Rate.

(d) Form of Payment. The Participant may elect, at any time before payment begins, to receive payment of his Restoration Benefit in the form of a Single Life Annuity, a Qualified Joint and Survivor Annuity, a Contingent Annuity Option or a Period Certain Option. Such election shall be made in writing in accordance with procedures established by the Plan

Administrator. If a Participant fails to elect a form of payment, payment shall be made as a Single Life Annuity if the Participant is unmarried when payment begins or a Qualified Joint and Survivor Annuity if the Participant is married when payment begins. A Participant may not change the form of payment after payment begins.

(e) Optional Elections as to Time of Payment. A Participant may elect, in accordance with the provisions of this subparagraph 24(e) and procedures established by the Plan Administrator, to defer payment of his Restoration Benefit payable under Paragraph 24 beyond the date on which payment would otherwise begin, provided that such election shall not apply to pre-retirement death benefits under this Plan. Any election made under this subparagraph 24(e) shall also apply if the Participant's Restoration Benefit is payable under Paragraph 20 instead of this Paragraph 24.

(1) Initial Election. A Participant may elect, at any time during the period beginning on the date he is designated as a Participant and ending 30 days after his Participation begins, to have payment of his Restoration Benefit commence on a specified date that is after the date as of which payment would otherwise commence under subparagraph 24(c); provided that such Participant shall have no vested interest in his Restoration Benefit until the later of (A) the date the Participant would otherwise become 100% vested pursuant to the terms of Paragraph 26 and (B) the first day of the 14th month following the date he enters the Plan (unless, prior to the later of such dates, a Participant who otherwise meets the conditions for 100% vesting pursuant to Paragraph 26 dies or becomes Disabled, in which case the Restoration Benefit, if any, shall be 100% vested).

(2) Subsequent Election. A Participant may elect at any time to defer payment of his Restoration Benefit to a specified date that is at least 5 years after the date on which payment would otherwise begin under subparagraph 24(c) or, if later, under an election made pursuant to subparagraph 24(e)(1); provided that such election will not become effective until 12 months after the date the election is made; and provided further that the election must be made at least 12 months before the date on which payment would otherwise begin.

25. PRE-RETIREMENT DEATH BENEFITS

The provisions of this Paragraph 25 describe the death benefits, if any, payable with respect to a Participant who dies with a surviving Spouse before payment of his Restoration Benefit (other than a Restoration Disability Benefit) begins. If there is no surviving Spouse, no death benefit will be payable.

(a) Death While an Active or Disabled Participant.

(1) Amount of Benefit. If an Active Participant or a Disabled Participant dies after age 55 or after completing at least 5 years of Service, then the Participant's surviving Spouse, if any, shall be entitled to receive a

Restoration Death Benefit, which shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit that would have been provided under Section 7.01(b) or (c) of the BHUH Pension Plan, as applicable, commencing on the first day of the month following the Participant's death or, if later, the first day of the month following the Participant's 55th birthday if such death benefit had been calculated using the Participant's Final Average Restoration Pay or Average Monthly Restoration Earnings, as applicable, and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under Section 7.01(b) or (c) of the BHUH Pension Plan, as applicable, commencing on the first day of the month following the Participant's death or, if later, the first day of the month following the Participant's 55th birthday.

If payment begins before the date the Participant would have attained age 55, the Plan benefit will be the Actuarial Equivalent of the benefit commencing at the date the Participant would have attained age 55.

(2) <u>Time of Payment and Form of Payment.</u> Payment of the monthly death benefit described in (1) above will commence within 60 days after the first day of the month following the later of (i) the date of the Participant's death or (ii) January 1, 2009. The last payment will be due on the first day of the month in which the death of the surviving Spouse occurs.

(b) <u>Death while Inactive; Less than 10 Years of Service and Terminated before Age 55</u>

(1) <u>Amount of Benefit</u>. If a Participant (other than a Disabled Participant) is not an Active Participant, had a Termination of Employment prior to age 55, has a vested right to his Restoration Benefit and dies at a time when he has less than 10 years of Service, then the Participant's surviving Spouse shall be entitled to receive a Restoration Benefit, which shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit that would have been provided under Section 7.01(d) of the BHUH Pension Plan commencing on (1) the first day of the month following the Participant's death or, if later, (2) the Participant's Normal Retirement Date if such benefit had been calculated using the Participant's Final Average Restoration Pay or Average Monthly Restoration Earnings, as applicable, and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under Section 7.01(d) of the BHUH Pension Plan commencing on (1) the first day of the month following the Participant's death or, if later (2) the Participant's Normal Retirement Date.

If payment begins on or after the date the Participant would have attained age 55 and before the Participant's Normal Retirement Date, the benefit will be reduced for early commencement using the deferred vested factors specified in Section 6.01 of the BHUH Pension Plan. If payment begins before the date the Participant would have attained age 55, the Plan benefit will be the Actuarial Equivalent of the benefit commencing at the date the Participant would have attained age 55.

(2) Time of Payment and Form of Payment. Payment of the monthly death benefit described in (1) will commence within 60 days after the first day of the month beginning after the later of (i) the date of the Participant's death or (ii) January 1, 2009. The last payment of the monthly death benefit will be due on the first day of the month in which the death of the surviving Spouse occurs.

(c) Death while Inactive; 10 or More Years of Service or Terminated after Age 55

(1) Amount of Benefit. If a Participant (other than a Disabled Participant) is not an Active Participant, either has at least 10 years of Service or had a Termination of Employment on or after age 55, dies, then the Participant's surviving Spouse shall be entitled to receive a Restoration Benefit, which shall be equal to the amount, if any, by which (A) exceeds (B), where

(A) is the Gross Monthly Death Benefit that would have been provided under Section 7.01(e) of the BHUH Pension Plan commencing on the first day of the month following the later of (1) the Participant's death and (2) the Participant's 55th birthday if such benefit had been calculated using the Participant's Final Average Restoration Pay or Average Monthly Restoration Earnings, as applicable, and determined without regard to the reduction in the Section 415 Benefit Limitation; and

(B) is the actual Gross Monthly Death Benefit payable under Section 7.01(e) of the BHUH Pension Plan commencing on the first day of the month following the later of (1) the Participant's death and (2) the Participant's 55th birthday.

If payment begins before the date the Participant would have attained age 55, the Plan benefit will be the Actuarial Equivalent of the benefit commencing at the date the Participant would have attained age 55.

(2) Time of Payment and Form of Payment. Payment of the monthly death benefit described in (1) will commence within 60 days after first day of the month following the later of (i) the date of the Participant's death or (ii) January 1, 2009. The last payment of the monthly death benefit will be due on the first day of the month in which the death of the surviving Spouse occurs.

26. VESTING

Except as otherwise provided herein (including, but not limited to, the provisions of subparagraph 24(e)(1)), a Participant's Restoration Benefit will vest only in accordance with the following table:

Years of Service	Percent of Benefit Vested
Less than 5 years	0
5 or more years	100

Notwithstanding the foregoing, a Participant's Restoration Benefit shall be 100% vested if the Participant is an Active Participant on or after his 55th birthday.

The provisions for vesting set forth in this paragraph are not intended to give any Participants any right or claim to any specific assets of the Company.

IN WITNESS WHEREOF, the amended and restated Plan has been approved and executed by a duly authorized officer of the Company on this 29th day of October, 2008, on behalf of the Company.

BLACK HILLS CORPORATION

By /s/ David R. Emery

David R. Emery
Chairman, President
and Chief Executive Officer

Exhibit 10.6

BLACK HILLS CORPORATION
NONQUALIFIED DEFERRED COMPENSATION PLAN
(As Amended and Restated effective January 1, 2009)

1. Purpose of Plan and Effective Date. The original effective date of this Black Hills Corporation Nonqualified Deferred Compensation Plan (“Plan”) was the 1st day of June, 1999. The purpose of the Plan is to provide benefits to a select group of management or highly compensated employees who contribute materially to the continued growth, development and future business success of the Company. It is the intention of the Company that this Plan shall be administered as an unfunded benefit plan established and maintained for a select group of management or highly compensated employees. This Plan is hereby amended and restated effective January 1, 2009. It is the intention of the Company that this Plan shall comply with Code Section 409A and the regulations issued thereunder effective January 1, 2009. During the period from January 1, 2005 though December 31, 2008, it is the intention of the Company to operate this Plan in reasonable good faith compliance with Code Section 409A and the interim guidance issued thereunder.

2. Definitions. For purposes of this Plan, the following phrases or terms have the indicated meanings unless otherwise clearly apparent from the context:

(a) “Affiliate” shall mean any business organization or legal entity that directly or indirectly, controls, is controlled by or is under common control with the Company. For purposes of this definition, the term “control” (including the terms “controlling”, “controlled by”, and “under common control with”) includes the possession, direct or indirect, of the power to vote 50 percent or more of the voting equity securities, membership interest, or other voting interest, or to direct or cause the direction of the management and policies of such business organization or other legal entity, whether through the ownership of voting equity securities, membership interest, by contract, or otherwise.

(b) “Base Salary” shall mean the compensation paid to a Participant by the Employer during a calendar year, including any compensation reduction under a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code or under a flexible benefit program under Section 125 of the Internal Revenue Code but not including any amounts paid to the Participant as overtime, bonus, commission, or incentive compensation, nor reimbursements and expense allowances, fringe benefits, moving expenses, nonqualified deferred compensation, or welfare benefits.

(c) “Base Salary Contribution” means that part of a Participant’s Base Salary that such Participant has elected to defer pursuant to Section 4.1.

(d) “Beneficiary” shall mean the person, persons, or estate of a Participant, entitled to receive any benefits subsequent to the death of a Participant under a Beneficiary Designation form entered into in accordance with the terms of this Plan.

(e) “Beneficiary Designation” shall mean the form of written agreement, by which the Participant names the Beneficiary(ies) under the Plan.

(f) “Board of Directors” shall mean the Board of Directors of the Company.

(g) “Change in Control” shall mean a change in the ownership or effective control of the Company or a Subsidiary, or a change in the ownership of a substantial portion of the assets of the Company or a Subsidiary, as defined under Code Section 409A and the regulations issued thereunder.

(h) “Code” shall mean the Internal Revenue Code of 1986, as amended.

(i) “Committee” shall mean the Compensation Committee of the Board of Directors.

(j) “Company” shall mean Black Hills Corporation, a South Dakota corporation, with principal offices in the State of South Dakota.

(k) “Employee” shall mean any person who is in the regular full-time employment of the Company or a Subsidiary, as determined by the personnel rules and practices of the Company or a Subsidiary. The term does not include persons who are retained by the Company or a Subsidiary solely as consultants.

(l) “Employer” shall mean the Company and any Subsidiary that duly adopts the Plan.

(m) “Incentive Contribution” means that portion of a Participant’s incentive award under the Company’s Short Term Annual Incentive Plan (“STIP”) which the Participant has elected to defer under the STIP and under Section 4.2.

(n) Key Employee” shall mean a Participant who is a specified employee, as defined as in Code Section 409A and the regulations and other official guidance issued thereunder, and as determined in accordance with procedures established by the Committee.

(o) “Participant” shall mean an Employee who is selected to participate in the Plan.

(p) “Participant’s Account” shall mean the memorandum account established and maintained by the Company for each Participant with respect to the Participant’s total interest in the Plan resulting from the Participant’s Base Salary Contributions and Incentive Contributions plus the earnings thereon.

(q) “Performance Share Contributions” shall mean that portion of a Participant’s Performance Share Award under the Company’s Omnibus Incentive Compensation Plan (the "Omnibus Plan") which the Participant has elected to defer under the Participant’s Performance Share Award Agreement and the Omnibus Incentive Plan and under Section 4.4.

(r) “Plan Year” shall mean the Plan’s accounting year of 12 months beginning on January 1 and ending on the following December 31.

(s) "RSU Contribution" means a Participant's restricted stock unit award under the Company's Omnibus Incentive Compensation Plan or any successor plan that the Participant has deferred pursuant to the terms of the restricted stock unit agreement between the Participant and the Company (the "RSU Agreement") and under Section 4.3.

(t) “Subsidiary” shall mean any business organization in which the Company, directly or indirectly owns a majority of its voting power or voting equity securities or equity interest and which the Board of Directors designates as a Subsidiary for purposes of this Plan.

(u) “Termination of Employment” shall separation from service with the Company and all Affiliates for any reason other than death, in accordance with the provisions of Code Section 409A.

3. Eligibility and Participation. In order to be eligible for participation in the Plan, an Employee must be selected by the Committee. The Committee, in its sole and absolute

discretion, shall determine eligibility for participation from among management or highly compensated employees of the Employer in accordance with the purposes of the Plan.

4. Contributions.

4.1 Base Salary Contributions. Each Participant may elect to defer up to 50% of the Participant's Base Salary for a Plan Year. An election to defer Base Salary must be made in writing prior to the beginning of a Plan Year. An election made with respect to a Participant's Base Salary for a Plan Year becomes irrevocable on the last day of the prior Plan Year. Except as otherwise provided herein, the election may not be changed during the Plan Year and remains in place for subsequent Plan Years until changed or revoked. A change or revocation with respect to a subsequent Plan Year must be made in writing before the end of the prior Plan Year.

Notwithstanding the foregoing, a newly eligible Participant may, within 30 days after the date he becomes eligible, elect in writing to defer Base Salary for the Plan Year in which he first becomes eligible, but only with respect to Base Salary earned subsequent to the election. Except as otherwise provided herein, such election is irrevocable with respect to the remainder of the Plan Year and remains in place for subsequent Plan Years until changed or revoked. A change or revocation with respect to a subsequent Plan Year must be made in writing before the end of the prior Plan Year.

The Participant's Base Salary Contribution shall be allocated to that Participant's Account on a monthly basis.

The Base Salary Contribution election of a Participant who receives an emergency withdrawal due to an Unforeseeable Emergency under Section 7.1 or a hardship distribution under a tax-qualified 401(k) plan maintained by the Company shall be cancelled. A Participant whose Base Salary Contribution election is cancelled due to an Unforeseeable Emergency under Section 7.1 may elect to resume Base Salary Contributions with respect to a Plan Year beginning after such distribution is made by making an election prior to the beginning of such Plan Year. A Participant whose Base Salary Contribution election is cancelled due to a hardship withdrawal under a tax-qualified 401(k) plan maintained by the Company may elect to resume Base Salary Contributions with respect to a Plan Year beginning at least 6 months after such withdrawal is made by making an election prior to the beginning of such Plan Year.

4.2 Incentive Contributions. A Participant may elect to defer the receipt of all or any portion of a Participant's incentive award under the STIP, including shares of Company stock. The deferral election must be filed by June 30 of the Plan Year prior to the Plan Year in which the Award will be determined or, if earlier, by the day before the date on which the Incentive Award has become readily ascertainable (as defined for purposes of Section 409A of the Internal Revenue Code). In no event shall an election to defer be effective unless the Participant is an employee at all times from the first day of the Plan Year prior to the Plan Year in which the Award will be determined (or, if later, the date the performance measures under the STIP for the Plan Year have been established) until the date the election is made. The amount of the incentive award deferred shall be allocated to a Participant's Account as of the date it would have been distributed if no deferral election had been made. In the event that Participant defers a stock award under the STIP, then the Company shall establish within the Participant's Account a common stock equivalent memorandum account ("Stock Account") and shall credit the Stock Account with Company common stock equivalents, including fractional equivalents. Appropriate adjustments shall be made to the Stock Account for stock splits, stock dividends, mergers, consolidation and other similar circumstances affecting the Company common stock.

4.3 RSU Contributions. A Participant who has been granted an award of Restricted Shares under the Omnibus Plan may elect to receive the entire award in the form of restricted stock units and defer the receipt thereof as an RSU Contribution. The election to receive restricted stock units must be made before the beginning of the Plan Year in which the grant of Restricted Shares is made. The amount of the award deferred under the Omnibus Plan and RSU Agreement shall be allocated to a Participant's Account upon receipt by the Company of the Participant's executed RSU Agreement. If the Participant does not vest in the award under the terms of the RSU Agreement, the deferral of the RSU Contribution shall be null and void. The Company shall establish within the Participant's Account a Stock Account for the RSU contribution (as defined in Section 4.2) and shall credit the Stock Account with Company common stock equivalents (but not actual shares), including fractional equivalents. Appropriate adjustments shall be made to the Stock Account for Stock splits, stock dividends, mergers, consolidation and other similar circumstances affecting the Company common stock. A Participant's RSU Contributions shall remain subject to, and shall vest in accordance with, the terms of the applicable RSU Agreement.

4.4 Performance Share Contributions. A Participant may elect under the terms of the Company's Omnibus Plan and his Performance Share Award Agreement, to defer the receipt of all or any portion of a Participant's Performance Share Award thereunder, including shares of Company stock. The election to defer must be made in writing before the beginning of the Performance Period specified in the Performance Share Award Agreement. The amount of the award deferred under the Omnibus Plan and Performance Share Award Agreement shall be allocated to a Participant's Account upon receipt by the Company of the Participant's deferral election. If the Participant does not vest in the award under the terms of the Performance Share Award Agreement, the deferral of the Performance Share Contribution shall be null and void. In the event that Participant defers a stock award, then the Company shall establish within the Participant's Account a common stock equivalent memorandum account ("Stock Account") and shall credit the Stock Account with Company common stock equivalents, including fractional equivalents. Appropriate adjustments shall be made to the Stock Account for stock splits, stock dividends, mergers, consolidation and other similar circumstances affecting the Company common stock. A Participant's Performance Share Contributions shall remain subject to, and shall vest in accordance with, the terms of the applicable Performance Share Award Agreement.

5. Earnings on Participant's Account. Each Participant may, at the time of his deferral election, choose to allocate the amount of Base Salary Contributions deferred and the amount of the Incentive Contributions deferred (except for the Company stock deferred) into certain categories of hypothetical investments to be determined by the Participant as are available under the range of investments as may be allowed by any third-party service provider to the Plan, or trustee, if any, or if none, from the range of investments as determined by the Committee in its discretion. The amounts deferred into a Participant's Account shall change in value based upon the allocated underlying hypothetical investments, including Company stock. RSU Contributions shall remain in Company stock equivalents until distribution.

6. Payment of Benefit.

6.1 Time of Payment. Upon a Participant's Termination of Employment, the Employer shall pay to or cause to be paid to such Participant the then amount in the Participant's Account. The amount in the Participant's Account shall be paid in cash, except that any amounts in the Participant's Stock Account attributable to Incentive Contributions, Performance Shares, or RSU Contributions shall be paid in the form of shares of Company common stock.

6.2. Form of Payment. Each time a Participant elects to make Base Salary Contributions, Incentive Contributions, RSU Contributions or Performance Share Contributions under Section 4.1, 4.2, 4.3, or 4.4, as applicable, the Participant shall choose one of the following payment options for the portion of his Account attributable to such Contributions and payable upon his Termination of Employment:

(a) a lump sum payment to be paid within 60 days after the Participant's Termination of Employment, or

(b) substantially equal annual or monthly installment payments over a period of years designated by Participant but not to exceed 15 years. If annual installments are elected, the first annual installment payment shall be made in cash to the Participant during the first 60 days of the Plan Year beginning after the Participant's Termination of Employment. The annual payment for each succeeding Plan Year shall be paid to the Participant during the first 60 days of the Plan Year. If monthly installments are elected, the first payment shall be made during the first 60 days of the Plan Year beginning after the Participant's Termination of Employment and shall include payments for January and February if payment is made during February, or payments for January, February and March if payment is made in March. Subsequent monthly payments shall be made to the Participant on the first day of each month. Subsequent to the first installment payment, accrued interest on the unpaid accumulated balance will be added to each subsequent payment based on amortization over the term of payment. The interest rate to be used shall be equal to the seven year United States Treasury Bond yield as determined on the Termination of Employment date.

A Participant who makes no election with respect to his Contributions shall be deemed to have elected to receive payment of his Account attributable to such Contributions in a lump sum. The Participant's election (or deemed election) of a payment option shall be irrevocable.

If the Participant dies after installment payments begin, the remaining Account balance shall be paid to the Participant's Beneficiary or Beneficiaries in a lump sum within 60 days after the Participant's death or, if later, by the end of the Plan Year in which the Participant's death occurred.

6.3 Special Election. Notwithstanding Section 6.2, each Participant who became a Participant before January 1, 2009 and who does not have a Termination of Employment before January 1, 2009 may elect, in writing and in accordance with procedures established by the Committee, to change the form of payment he previously elected for payment of his Account upon his Termination of Employment. Such election shall apply to all or any portion of his Account, as the Participant shall specify, and shall be irrevocable.

6.4 Payment to Key Employees. Notwithstanding any provision of this Section 6 to the contrary, if payment of a Key Employee's Account is to be made because of the Key Employee's Termination of Employment, payment to such Key Employee shall begin on or within 60 days after the first day of the seventh month after the Participant's Termination of Employment or, if later, on the date payment would otherwise begin under this Section 6. If the Key Employee elected to receive monthly installments, and if payment is delayed under this Section 6.4, the first payment to the Key Employee shall include a lump sum equal to the sum of the missed monthly payments, plus interest at the rate specified in Section 6.2(b) for the period of the delay. If the Key Employee elected to receive a lump sum or annual installments, and if payment is delayed under this Section 6.4, the first payment to the Key Employee shall include interest at the rate specified in Section 6.2(b) for the period of the delay.

7. Accelerated Payment.

7.1 Unforeseeable Emergency. Notwithstanding Section 6 above, a Participant who has suffered an Unforeseeable Emergency, as hereafter defined, may apply to withdraw amounts from the Participant's Account to the extent reasonably needed to satisfy the Unforeseeable Emergency. If the Committee, in its sole discretion, determines that an Unforeseeable Emergency has occurred, it shall pay to the Participant that portion of his Account which the Committee determines is necessary to satisfy the emergency need, including any amounts necessary to pay any federal, state or local income taxes reasonably anticipated to result from the distribution. Payment shall be made in a lump sum. A Participant requesting an emergency payment shall apply for the payment in writing on a form approved by the Committee and shall provide such additional information as the Committee may require. For purposes of this Section, "Unforeseeable Emergency" means a severe financial hardship to the Participant resulting from any of the following:

(a) An accident or illness of the Participant or the Participant's spouse, Beneficiary or dependent (as defined in Code section 152 without regard to Code section 152(b)(1), (b)(2) or (d)(1)(B));

(b) Loss of the Participant's property due to casualty, including the need to rebuild a home following damage not otherwise covered by insurance;

(c) Any other similar extraordinary and unforeseeable circumstance that the Committee, in its sole discretion, determines constitutes an unforeseen emergency which is not relieved by compensation through insurance or otherwise, and which cannot reasonably be relieved by the liquidation of the Participant's other assets without causing severe financial hardship.

7.2 Domestic Relations Order Notwithstanding any provision of Section 6 to the contrary, the Committee may, in its discretion, distribute a portion of the Participant's Account to the extent necessary to satisfy the terms of a domestic relations order, as defined under Code Section 414(p)(1)(B).

8. Death Benefits. If a Participant dies before payment begins under Section 6, the Employer will pay or cause the balance of the Participant's Account to be paid in a lump sum to such Participant's Beneficiary. Payment will be made by the last day of the Plan Year in which the death occurred or, if later, within 60 days after the date of the death. Proof of death must be furnished in a form acceptable to the Committee.

9. Change in Control. In the event of a Change in Control, the Participant's Account shall be distributed as if the Participant's Termination of Employment had occurred, whether or not Participant's employment status with the Employer or any successor of the Employer has changed.

10. Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries to receive benefits under the Plan by completing the Beneficiary Designation. If more than one Beneficiary is named, the shares or precedence of each Beneficiary shall be indicated. A Participant shall have the right to change the Beneficiary by submitting to the Committee a new Beneficiary Designation. The Beneficiary Designation must be approved in writing by the Committee; however, upon the Committee's acknowledgement of approval, the effective date of the Beneficiary Designation shall be the date it was executed by the Participant. If the Committee has any doubt as to the proper Beneficiary to receive payments, it shall have the right to withhold payments until the matter is finally adjudicated or to interplead the Participant's Account into a court of competent jurisdiction. Any payment made by the Employer in good faith

and in accordance with the provisions of this Plan and a Participant's Beneficiary Designation shall fully discharge the Employer and Committee from all further obligations with respect to the payment.

11. Source of Benefits.

11.1 Benefits Payable from General Assets. Amounts payable shall be paid exclusively from the general assets of the Employer, and no person entitled to payment shall have any claim, right, security interest, or other interest in any fund, trust, account, or other asset of the Employer that may be looked to for payment. The Employer's liability for the payment of benefits shall be evidenced only by this Plan. In all events, it is the intent of the Employer that the Plan be treated as unfunded for tax purposes and for purposes of Title I of ERISA.

11.2 Investments to Facilitate Payment of Benefits. Although the Employer is not obligated to invest in any specific asset or fund in order to provide the means for the payment of any liabilities under this Plan, the employer may elect to do so and may also elect to acquire life insurance policies on any Participant or create a "Rabbi" trust.

The Participant also understands and agrees that the participation of Participant, in any way, in the acquisition of any insurance policy or any other general asset by the Employer shall not constitute a representation to the Participant, the designated recipient, or any person claiming through the Participant that any of them has a special or beneficial interest in the general asset.

11.3 Employer Obligation. The Employer shall have no obligation of any nature whatsoever to a Participant under this Plan other than what is specifically stated in the Plan.

12. Termination of Employment. This Plan does not obligate the Employer to continue the employment of a Participant with the Employer nor does it limit the right of the Employer at any time and for any reason to terminate the Participant's employment. Termination of a Participant's employment with the Employer for any reason, whether by action of the Employer or otherwise, shall immediately terminate a Participant's continued participation in this Plan. In no event shall this Plan by its terms or implications constitute an employment contract of any nature whatsoever between the Employer and a Participant.

13. Terminations, Amendments, Modification or Supplement of Plan. The Employer reserves the right to terminate, amend, modify or supplement this Plan, wholly or partially, and from time to time, at any time. Such right to terminate, amend, modify, or supplement this Plan shall be exercised for the Employer by the Board of Directors; provided, however, that no action to terminate this Plan shall be taken except upon written notice to each Participant to be affected, which notice shall be given not less than 30 days prior to the action. Any action under this Section 14.1 shall not affect rights previously accrued under this Plan. Notwithstanding the foregoing, the Company intends that any amendment, modification or termination shall be in accordance with the provisions of Code Section 409A and that adverse tax consequences for Participants under Code Section 409A not result from such amendment, modification, or termination.

14. Other Benefits and Agreements. The benefits provided for a Participant and any Beneficiary hereunder and under this Plan are in addition to any other benefits available to such Participant under any other program or plan of the Employer for its employees, and, except as may otherwise be expressly provided for, this Plan shall supplement and shall not supersede, modify, or amend any other program or plan of the Employer or a Participant.

15. Restrictions on Alienation of Benefits. No right or benefit under this Plan shall be subject to sale, assignment, or encumbrances, and any attempt to sell, assign, or encumber the Plan shall be void. No right or benefit hereunder shall in any manner be liable for or subject to the debts, contract, liabilities, or torts of the person entitled to such benefit. If any Participant or Beneficiary under this Plan should become bankrupt or attempt to sell, assign, or encumber any right to a benefit under this Plan then such right or benefit shall, in the discretion of the Committee, terminate, and, in that event, the Committee shall hold or apply the same or any part of it for the benefit of the Participant or Beneficiary, or the Participant's spouse, children, or other dependents, in a manner and in a portion that the Committee, in its sole and absolute discretion, may deem proper.

16. Withholding. There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their Beneficiaries will bear any and all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

17. Administration of this Plan.

17.1 Appointment of Committee. The general administration of this Plan, as well as its construction and interpretation, shall be vested in the Committee or its successor, as the members of which are designated and appointed from time to time by the Board of Directors. Notwithstanding the foregoing, the Company intends that construction interpretation of the Plan shall in accordance with the provisions of Code Section 409A and that adverse tax consequences for Participants under Code Section 409A not result from such construction or interpretation.

17.2 Committee Rules and Powers – General. Subject to the provisions of this Plan, the Committee shall from time to time establish rules, forms, and procedures for the administration of this Plan. Such decisions, actions and records of the Committee shall be conclusive and binding upon the Employer and all persons having or claiming to have any right or interest in or under the Plan.

17.3 Reliance of Certificate, Etc. The members of the Committee and the officers and directors of the Employer shall be entitled to rely on all certificates and reports made by any duly appointed accountants, and on all opinions given by any duly appointed legal counsel. Such legal counsel may be counsel for the Employer.

17.4 Determination of Benefits. In addition to the powers specified, the committee shall have the power to compute and certify under this Plan the amount and kind of benefits from time to time payable to Participants and their Beneficiaries and to authorize all disbursements for such purposes.

17.5 Information to Committee. To enable the Committee to perform its functions, the Employer shall supply full and timely information to the Committee on all matters relating to the compensation of all Participants, their retirement, death or other cause for termination of employment and such other pertinent facts as the Committee may require.

18. Claims. All claims for benefits under the Plan shall be made to the Committee. If the Committee denies a claim, the Committee may provide notice to the Participant or beneficiary, in writing, within 90 days after the claim is filed unless special circumstances require an extension of time for processing the claim, not exceed an additional 90 days. If the Committee does not notify the Participant or Beneficiary of the denial of the claim within the time period specified above, then the claim shall be deemed denied. The notice of a denial of a claims shall be written in a manner calculated to be understood by the claimant and shall set forth (1)

specific references to the pertinent Plan provisions on which the denial is based; (2) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation as to why such information is necessary; and (3) an explanation of the Plan's claim procedure.

Within 60 days after receipt of the above material, the claimant shall have a reasonable opportunity to appeal the claim denial to the Committee for a full and fair review. The claimant or his duly authorized representative may (1) request a review upon written notice to the Committee; (2) review pertinent documents; and (3) submit issues and comments in writing.

A decision on the review by the Committee will be made not later than 60 days after receipt of a request for review, unless special circumstances require an extension of time for processing (such as the need to hold a hearing), in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. The decision on review shall be in writing and shall include specific reasons for the decision, written in a manner calculated to be understood by the claimant, as well as specific references to the pertinent Plan provisions on which the decision is based.

19. Miscellaneous.

19.1 Execution of Receipts and Releases. Any payment to any Participant, a Participant's legal representative, or Beneficiary in accordance with the provisions of this Plan shall, to the extent thereof, be in full satisfaction of all claims against the Employer. The employer may require the Participant, legal representative, or Beneficiary, as a condition precedent to payment, to execute a receipt and release in a form it may determine.

19.2 No Guarantee of Interests. Neither the Committee nor any of its members guarantees the payment of any amounts which may be or become due to any person or entity under this Plan. The liability of the Employer to make any payment under this Plan is limited to the then available assets of the Employer.

19.3 Employer Records. Records of the Employer as to a Participant's employment, termination of employment and the reason therefore, re-employment, authorized leaves of absence, and compensation shall be conclusive on all persons and entities, unless determined to incorrect.

19.4 Evidence. Evidence required of anyone under this Plan and any Plan Agreement executed may be by certificate, affidavit, document, or other information which the person or entity acting on it considers pertinent and reliable, and signed, made, or presented by the proper party or parties.

19.5 Administration Expenses. The Company shall bear all costs and expenses necessary to administer the Plan.

19.6 Notice. Any notice which shall or may be given under this Plan shall be in writing and shall be mailed by United States mail, postage prepaid. If notice is to be given to the Employer, such notice shall be addressed to the Employer at:

Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709
Attn: Secretary of Black Hills Corporation.

19.7 Change of Address. Any party may, from time to time, change the address to which notices shall be mailed by giving written notice of such new address.

19.8 Effect of Provisions. The provisions of this Plan shall be binding upon the Employer and its successors and assigns, and upon the Participant, Beneficiaries, assigns, heirs, executors and administrators.

19.9 Headings. The titles and headings of Articles and Sections are included for convenience of reference only and are not to be considered in the construction of the provisions hereof.

19.10 Governing Law. All questions arising with respect to this Plan shall be determined by reference to the laws of the State of South Dakota unless preempted by federal law.

BLACK HILLS CORPORATION

By: /s/ David R. Emery
Chairman, President and CEO

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Exhibit 10.11

**FIRST AMENDMENT TO THE
2005 OMNIBUS INCENTIVE PLAN
OF BLACK HILLS CORPORATION**

WHEREAS, Black Hills Corporation (the “Company”) maintains the “2005 Omnibus Incentive Plan of Black Hills Corporation” (the “Plan”); and

WHEREAS, pursuant to Section 18.4 of the Plan, the Board of Directors of the Company (the “Board”) reserved the right to amend the Plan or an Award Agreement granted under the Plan at any time, “to take effect retroactively or otherwise, as deemed necessary or advisable for the purpose of conforming the Plan or an Award Agreement to any present or future law relating to plans of this or similar nature (including, but not limited to, Code Section 409A), and to the administrative regulations and rulings promulgated thereunder”; and

WHEREAS, pursuant to Article 8 of the Plan, the Committee has issued Restricted Stock Units under the Plan under the form of the “Black Hills Corporation 2005 Omnibus Incentive Plan Restricted Stock Unit Agreement” (the “RSU Award Agreement”); and

WHEREAS, pursuant to Article 9 of the Plan, the Committee has issued Performance Shares under the Plan under the form of the “Incentive Compensation Plan Performance Share Award Agreement, Black Hills Corporation” (the “PSA Award Agreement”); and

WHEREAS, outstanding RSU Award Agreements and PSA Award Agreements may provide for deferrals of compensation that could be subject to Section 409A of the Internal Revenue Code of 1986, as amended, and the regulations and other authority thereunder (“Code”); and

WHEREAS, the Company intends that all deferrals of compensation pursuant to the Plan be exempt from, or in compliance with, Code Section 409A; and

WHEREAS, the Board now desires to amend the Plan in order to incorporate such terms and provisions as are deemed necessary or appropriate for exemption from, or compliance with, Code Section 409A;

NOW THEREFORE BE RESOLVED, that the Plan is hereby amended by this First Amendment, effective as of December 31, 2008, as follows:

1. A new Section 2.46 “Disability” is added to the Plan as follows:

“Disability” means the Participant is (a) unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or to last for a continuous period of not less than 12 months, the Participant is receiving income replacement benefits for a period of not less than three months under an accident and health plan covering employees of the Company or an Affiliate. Any determination of Disability shall be made in accordance with the requirements of Code Section 409A. Any reference in the Plan or an Award Agreement to "disability" means a "Disability" as defined in the previous sentence.

2. A new Section 2.47, "Separation from Service", is added to the Plan as follows:

"Separation from Service" means (a) an Employee has terminated from employment, for whatever reason, with the Company and all of its Affiliates, or (b) a Director who is not an Employee has terminated his directorship with the Company for whatever reason. In each case, such term shall be construed to have the same meaning as the term "separation from service" under Code Section 409A.

3. A new Section 2.48, "Specified Employee", is added to the Plan as follows:

"Specified Employee" means a Participant who is a "specified employee", as defined in Code Section 409A and as designated as such by the Company for the applicable identification period under Code Section 409A.

4. Section 21.14 is amended, in its entirety, to provide as follows:

21.14 No Deferred Compensation. The Committee may permit deferrals of compensation pursuant to the Plan, or a separate plan, subplan or agreement, which meets the applicable requirements of Code Section 409A and the regulations and other authoritative guidance thereunder (collectively "Section 409A"). Additionally, to the extent any Award is subject to Section 409A, notwithstanding any provision herein to the contrary, the Plan does not permit the acceleration of the time or schedule of any distribution related to such Award, including, without limitation to any Specified Employee, except as permitted by Section 409A.

To the extent applicable, the Plan is intended to comply with Section 409A and shall be interpreted accordingly. The Company reserves the right to amend or modify the Plan (and any Award Agreement hereunder) in good faith to the minimum extent necessary so that it can be administered in compliance with Section 409A. Any ambiguous provision will be construed in a manner that is compliant with, or exempt from, the application of Section 409A. If any provision of this Plan (or any Award Agreement hereunder) would cause the Participant to incur any additional tax or interest under Section 409A, the Company shall, after consulting with the Participant, reform such provision to comply with Section 409A to the extent permitted under Section 409A.

Except for the Amendment above, the Plan shall remain in full force and effect.

Black Hills Corporation

By: /s/ David R. Emery
David R. Emery
Chairman, President and CEO

Exhibit 10.13

Black Hills Corporation
2005 Omnibus Incentive Plan
Option Award Agreement
(Effective for awards granted on or after January 1, 2009)

Participant:	____________
Date of Grant:	____________
Number of Shares Covered by this Option:	____________
Number of above Shares intended to be Incentive Stock Options ("ISOs") within the meaning of Internal Revenue Code § 422:	____________
Number of above shares intended to be Nonqualified Stock Options ("NQSOs"):	____________
Option Price for each Share:	____________
Date of Expiration:	____________

This document constitutes part of the prospectus covering securities that have been registered under the Securities Act of 1933.

THIS AGREEMENT, effective as of the Date of Grant set forth above, represents the grant of stock options by Black Hills Corporation, a South Dakota corporation (the "Company") to the Participant named above, pursuant to the provisions of the Black Hills Corporation 2005 Omnibus Incentive Plan ("Plan").

This Agreement and the Plan together govern your rights to the award and set forth all of the conditions and limitations affecting such rights. All capitalized terms used herein shall have the meanings ascribed to them in the Plan unless specifically set forth otherwise herein. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall completely supersede and replace the conflicting terms of this Agreement. By signing below, you agree to be bound by all the provisions of the Plan and this Agreement.

1. **Grant of Stock Options**. The Company hereby grants to the Participant an Option to purchase the number of Shares set forth above, at the stated Option Price, which is 100 percent (100%) of the Fair Market Value of a Share on the Date of Grant, in the manner and subject to the terms and conditions of the Plan and this Agreement.

2. **Exercise of Stock Option**. Except as hereinafter provided, the Participant may exercise this Option at any time after the end of one year following the Date of Grant as to those Shares which have become vested according to the vesting schedule set forth below, provided that no exercise may occur subsequent to the close of business on the Date of Expiration (as defined on page 1 of this Agreement).

VESTING SCHEDULE

Date	**Shares for Which Option Becomes Exercisable**	**Cumulative Number of Shares Available for Purchase**
______	___	____
______	___	____
______	___	____

This Option may be exercised in whole or in part, but not for less than 100 Shares at any one time, unless fewer than 100 Shares then remain subject to the Option, and the Option is then being exercised as to all such remaining Shares.

3. **Termination of Employment**:

(a) *By death or Disability*: In the event the Participant’s employment is terminated by reason of death or disability, all Shares under this Option shall become immediately vested (100%) and the Shares may be purchased under the terms of this Agreement until the earlier of: (i) the expiration date of this Option; or (ii) the first anniversary of the date of death or Disability.

(b) *By Retirement*: In the event of termination of employment by reason of retirement, all unvested Shares under this Option shall be forfeited and vested Shares may be purchased under the terms of this Agreement until the earlier of: (i) the expiration date of this Option; or (ii) the third anniversary date of Retirement.

(c) *For other reasons*: Shares which are vested as of the date of termination of employment of the Participant for any reason other than those reasons set forth in 3(a) or 3(b) above may be purchased under the terms of this Agreement until the earlier of: (i) the expiration date of this Option; or (ii) 90 days following the date of termination of employment. Shares which are not vested as of the date of termination shall immediately terminate, and shall be forfeited to the Company.

4. **Change in Control**. In the event of a Change in Control, all Shares under this Option shall become immediately vested (100%) and shall remain exercisable for their entire term.

"Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any of the following events:

(a) The acquisition in a transaction or series of transactions within a 12 month period by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Agreement, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c) (i), (ii) and (iii), below;

(b) Individuals who, as of December 31, 2007 are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least a majority of the members of the Board within a 12 month period; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest;

(c) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company and/or its subsidiaries, or a sale or other disposition (whether by sale, taxable or non-taxable exchange, formation of a joint venture or otherwise) of fifty percent (50%) or more of the assets of the Company and/or its subsidiaries (each a “Business Combination”), unless, in each case, immediately following such Business Combination, (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more that fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company’s assets either directly or through one (1) or more subsidiaries)(the “Successor Entity”); (ii) no Person (excluding any Successor entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c) (i), (ii), and (iii) above.

(e) A Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common Stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding Common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(f) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

5. **Restrictions on Transfer**. This Option may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, this Option shall be exercisable during the Participant's lifetime only by the Participant or the Participant's legal representative.

6. **Recapitalization**. In the event there is any change in the Company's Shares through the declaration of stock dividends or through recapitalization resulting in stock splits or through merger, consolidation, exchange of Shares, or otherwise, the number and class of Shares subject to this Option, as well as the Option Price, may be equitably adjusted by the Committee, in its sole discretion, to prevent dilution or enlargement of rights.

7. **Procedure for Exercise of Option**. This Option may be exercised by delivery of written notice to the Company at its executive offices, addressed to the attention of its Secretary. Such notice: (a) shall be signed by the Participant or his or her legal representative; (b) shall specify the number of full Shares then elected to be purchased with respect to the Option; (c) unless a Registration Statement under the Securities Act of 1933 is in effect with respect to the Shares to be purchased, shall contain a representation of the Participant that the Shares are being acquired by him or her for investment and with no present intention of selling or transferring them, and that he or she will not sell or otherwise transfer the Shares except in compliance with all applicable securities laws and requirements of any stock exchange upon which the Shares may then be listed; and (d) shall be accompanied by payment in full of the Option Price of the Shares to be purchased, and the Participant's copy of this Agreement.

The Option Price upon exercise of this Option shall be payable to the Company in full either: (a) in cash or its equivalent (acceptable cash equivalents shall be determined at the sole discretion of the Committee); or (b) by tendering previously acquired Shares having an aggregate Fair Market Value at the time of exercise equal to the total Option Price (provided that the Shares which are tendered must have been held by the Participant for at least six (6) months prior to their tender to satisfy the Option Price); or (c), by a combination of (a) and (b).

The Participant may also be permitted to exercise pursuant to a "cashless exercise" procedure as permitted under the Federal Reserve Board's Regulation T, subject to securities law restrictions.

As promptly as practicable after receipt of notice and payment upon exercise, the Company shall cause to be issued and delivered to the Participant or his or her legal representative, as the case may be, certificates for the Shares so purchased, which may, if appropriate, be endorsed with appropriate restrictive legends. The Share certificates shall be issued in the Participant's name (or, at the discretion of the Participant, jointly in the names of the Participant and the Participant's spouse). The Company shall maintain a record of all information pertaining to the Participant's rights under this Agreement, including the number of Shares for which their Option is exercisable. If the Option shall have been exercised in full, this Agreement shall be returned to the Company and canceled.

8. **Forfeiture and Repayment.**

(a) In the event the Participant’s employment is terminated for reasons other than those described in Sections 3 and 4 herein, all outstanding Shares under this Option shall immediately be forfeited by the Participant.

(b) Without limiting the generality of Section 8(a), the Company reserves the right to cancel all Shares under this Option awarded hereunder, whether or not vested, and require the Participant to repay all income or gains previously realized in respect of such Shares under this Option, in the event of the occurrence of any of the following events:

(i) termination of Participant’s employment for Cause;

(ii) within one year following any termination of Participant’s employment, the Board determines that the Participant engaged in conduct before the Participant’s termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant’s employment or the twelve month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct; or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Board determines that the Participant's conduct, activities or circumstances constitute events described in Section 8(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

(i) cancel any Shares under this Option awarded hereby, whether or not vested; and/or

(ii) require the Participant to repay an amount equal to all income or gain realized in respect of all such Shares under this Option. The amount of repayment shall include, without limitation, amounts received in connection with the delivery or sale of Shares under this Option or cash paid in respect of any Shares under this Option.

There shall be no forfeiture or repayment under Section 8(b) following a Change-in-Control.

(d) The Board, in its discretion, shall determine whether a Participant's conduct, activities or circumstances constitute events described in Section 8(b) and whether and to what extent the Shares under this Option awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Section 8(c). The Board shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant's outstanding Shares under this Option pending an investigation of a bona fide dispute regarding Participant's eligibility to receive a payment under the terms of this Agreement as determined by the Board in good faith.

(e) For purposes of applying this provision:

(i) "Cause" means any of the following:

(u) a Participant's violation of his or her material duties to the Company or any of its affiliates, which continues after written notice from the Company or any affiliate to cure such violation;

(v) Participant’s willful failure to follow the lawful written directives of the Board in any material respect;

(w) Participant’s willful misconduct in connection with the performance of any of his or her duties, including but not limited to falsifying or attempting to falsify documents, books or records of the Company or any of its affiliates, making or delivering a false representation, statement or certification of compliance to the Company, misappropriating or attempting to misappropriate funds or other property of the Company or any of its affiliates, or securing or attempting to secure any personal profit in connection with any transaction entered into on behalf of the Company or any of its affiliates;

(x) Participant’s breach of any material provisions of this Agreement or any other non-competition, non-interference, non-disclosure, confidentiality or other similar agreement executed by Participant with the Company or any of its affiliates;

(y) conviction (or plea of *nolo contendere*) of the Participant of any felony, or a misdemeanor involving false statement, in connection with conduct involving the Company or any of its subsidiaries or affiliates; or

(z) intentional engagement in any activity which would constitute or cause a breach of duty of loyalty, or any fiduciary duty to the Company or any of its subsidiaries or affiliates.

(ii) “Code of Conduct” means any code of ethics or code of conduct now or hereafter adopted by the Company or any of its affiliates, including to the extent applicable the Company’s Employee Conduct and Disclosure Policy dated November 22, 1999, as amended or supplemented from time to time, and the Company’s or subsidiary Risk Management Policies and Procedures, as amended, supplemented or replaced from time to time.

(f) Participant agrees that the provisions of this Section 8 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant’s agreement to the provisions of this Section 8, the Company would not have entered into this Agreement.

9. **Beneficiary Designation**. The Participant may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under this Agreement is to be paid in case of his or her death before he or she receives any or all of such benefit. Each such designation shall revoke all prior designations by the Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Secretary of the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

10. **Rights as a Shareholder**. The Participant shall have no rights as a shareholder of the Company with respect to the Shares subject to this Option Agreement including, without limitation, any right to dividends, until such time as the purchase price has been paid, and the Shares have been issued and delivered to him or her.

11. **Continuation of Employment**. This Option Agreement shall not confer upon the Participant any right to continuation of employment by the Company, nor shall this Option Agreement interfere in any way with the Company's right to terminate the Participant's employment at any time, for any reason. A transfer of the Participant's employment between the Company and any one of its Subsidiaries (or between Subsidiaries) shall not be deemed a termination of employment. Participant further agrees that awards made pursuant to this Agreement are discretionary, and do not constitute a benefit which the Company is obligated to make available to Participant, and therefore, nothing in this Agreement shall be deemed to constitute a contract of employment, or otherwise alter the at-will employment relationship between Participant and the Company.

12. **Limitation**. Participant shall not exercise any shares which are intended to be ISOs hereunder if and to the extent that the Participant would thereby be entitled to purchase Shares in any one calendar year, the value of which, determined at the time of the Date of Grant, would exceed $100,000.

13. **Miscellaneous**.

(a) This Option Agreement and the rights of the Participant hereunder are subject to all the terms and conditions of the Plan, as the same may be amended from time to time, as well as to such rules and regulations as the Committee may adopt for administration of the Plan. The Committee shall have the right to impose such restrictions on any Shares acquired pursuant to the exercise of this Option, as it may deem advisable, including, without limitation, restrictions under applicable Federal securities laws, under the requirements of any stock exchange or market upon which such Shares are then listed and/or traded, and under any blue sky or state securities laws applicable to such Shares. It is expressly understood that the Committee is authorized to administer, construe, and make all determinations necessary or appropriate to the administration of the Plan and this Option Agreement, all of which shall be binding upon the Participant.

(b) With the approval of the Board, the Committee may terminate, amend, or modify the Plan; provided, however, that no such termination, amendment, or modification of the Plan may in any material way adversely affect the Participant's rights under this Agreement, without the written consent of the Participant.

(c) The Company shall have the power and the right to deduct or withhold, or require the Participant to remit to the Company, an amount sufficient to satisfy federal, state, and local taxes (including Participant's FICA obligation) required by law to be withheld with respect to any exercise of the Participant's rights under this Agreement.

The Participant may elect, subject to any procedural rules adopted by the Committee, to satisfy the withholding requirement, in whole or in part, by having the Company withhold Shares having an aggregate Fair Market Value on the date the tax is to be determined, equal to the amount required to be withheld.

(d) The Participant agrees to take all steps necessary to comply with all applicable provisions of federal and state securities law in exercising his or her rights under this Agreement.

(e) This Agreement shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

(f) All obligations of the Company under the Plan and this Agreement, with respect to this Option, shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, or otherwise, of all or substantially all of the business and/or assets of the Company.

(g) To the extent not preempted by federal law, this Agreement shall be governed by, and construed in accordance with, the laws of the State of South Dakota.

SIGNATURE PAGE FOLLOWS

The following parties have caused this Agreement to be executed as of the Date of Grant.

BLACK HILLS CORPORATION

By____

Please acknowledge your agreement to participate in the Plan and this Agreement, and to abide by all of the governing terms and provisions, by signing the following representation:

Agreement to Participate

By signing a copy of this Agreement and returning it to Roxann R. Basham, Vice President Governance and Corporate Secretary of Black Hills Corporation, I acknowledge that I have read the Plan, and that I fully understand all of my rights under the Plan, as well as all of the terms and conditions which may limit my eligibility to exercise this Award. Without limiting the generality of the preceding sentence, I understand that my right to exercise this Award is conditioned upon my continued employment with Black Hills Corporation or its Subsidiaries.

____
Participant

Black Hills Corporation
2005 Omnibus Incentive Plan
Restricted Stock Award Agreement
(Effective for Awards granted on or after January 1, 2009)

Dear ________________________:

Congratulations on your selection as a Participant of Black Hills Corporation 2005 Omnibus Incentive Plan (the "Plan"). This Agreement and the Plan together govern your rights to the award and set forth all of the conditions and limitations affecting such rights. All capitalized terms shall have the meanings ascribed to them in the Plan unless specifically set forth otherwise herein. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall supersede and replace the conflicting terms of this Agreement. By signing below, you agree to be bound by all the provisions of the Plan and this Agreement.

Overview of Your Award

1. **Number of Restricted Shares Granted.** __________________________

2. **Date of Grant.** __________________________

3. **Date of Lapse of Restrictions**.

Shares	Date
_____________________________	_____________
_____________________________	_____________
_____________________________	_____________

4. **Employment by the Company**. This Restricted Stock is awarded on the condition that the Participant remain in the employ of Black Hills Corporation and its Affiliates (the "Company") from the Date of Grant through (and including) the Dates of Lapse of Restrictions. The Award of this Restricted Stock, however, shall not impose upon the Company any obligations to retain the Participant in its employ for any given period or upon any specific terms of employment.

5. **Certificate Legend**. Shares of Restricted Stock granted pursuant to the Plan shall be held by the Company in book entry form and shall be designated to have the following legend:

> "The sale or other transfer of the shares of stock represented by this certificate, whether voluntary, involuntary, or by operation of law, is subject to certain restrictions on transfer set forth in the Black Hills Corporation 2005 Omnibus Incentive Plan and in a Restricted Stock Award Agreement. A copy of the Plan

and such Restricted Stock Agreement may be obtained from the Secretary of Black Hills Corporation."

6. **Removal of Restrictions**. Except as otherwise provided in the Plan, each of the Shares of Restricted Stock granted under this Agreement shall become freely transferable by the Participant on each of the "Dates of Lapse of Restrictions" set forth on Paragraph 3 herein.

   Once the shares are released from the restrictions, the Participant shall be entitled to receive certificates representing the Shares of stock which have been vested, without the restrictive legend required by Paragraph 5 of this Agreement.

   Notwithstanding the terms of this Agreement, no stock shall be issued by the Corporation while its stock transfer books are closed.

7. **Voting Rights and Dividends**. During the Period of Restriction, the Participant may exercise full voting rights and is entitled to receive all dividends and other distributions paid with respect to the Shares of Restricted Stock while they are held. If any such dividends or distributions are paid in shares of Common Stock of the Company, the Shares shall be subject to the same restrictions on transferability as the Shares of Restricted Stock with respect to which they were paid.

8. **Termination of Employment By Reasons of Death or Disability, and Vesting in Connection with a Change in Control**. In the event the Participant's employment is terminated by reason of Death or Disability, or in the event of a Change in Control prior to the Dates of Lapse of Restrictions, all Shares of Restricted Stock then outstanding shall immediately vest one hundred percent (100%), and as soon as is administratively practicable, the stock certificates representing the Shares of Restricted Stock without any restrictions or legend thereon, shall be delivered to the Participant's beneficiary or estate.

   "Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any of the following events:

   (a) The acquisition in a transaction or series of transactions within a 12 month period by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Agreement, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c) (i), (ii) and (iii), below;

   (b) Individuals who, as of December 31, 2007 are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least a majority of the members of the Board within a 12 month period; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest;

(c) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company and/or its subsidiaries, or a sale or other disposition (whether by sale, taxable or non-taxable exchange, formation of a joint venture or otherwise) of fifty percent (50%) or more of the assets of the Company and/or its subsidiaries (each a “Business Combination”), unless, in each case, immediately following such Business Combination, (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more that fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company’s assets either directly or through one (1) or more subsidiaries)(the “Successor Entity”); (ii) no Person (excluding any Successor entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c) (i), (ii), and (iii) above.

(e) A Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common Stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding Common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(f) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

9. **Beneficiary Designation**. The Participant may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under this Agreement is to be paid in case of his or her death prior to the Dates of Lapse of Restrictions. Each such designation shall revoke all prior designations by the Participant, shall be in a form

prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. In the absence of any such designation, benefits remaining unpaid at the Participant's death shall be paid to the Participant's estate.

10. **Forfeiture and Repayment.**

(a) In the event the Participant's employment is terminated for reasons other than those described in Section 8 herein prior to the Dates of the Lapse of Restrictions, all outstanding Shares of unvested Restricted Stock granted hereunder shall immediately be forfeited by the Participant.

(b) Without limiting the generality of Section 10(a), the Company reserves the right to cancel all Restricted Stock awarded hereunder, whether or not vested, and require the Participant to repay all income or gains previously realized in respect of such Restricted Stock, in the event of the occurrence of any of the following events:

(i) termination of Participant's employment for Cause;

(ii) within one year following any termination of Participant's employment, the Board determines that the Participant engaged in conduct before the Participant's termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant's employment or the twelve month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct; or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Board determines that the Participant's conduct, activities or circumstances constitute events described in Section 10(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

(i) cancel any Shares of Restricted Stock awarded hereby, whether or not vested; and/or

(ii) require the Participant to repay an amount equal to all income or gain realized in respect of all such Restricted Stock. The amount of repayment shall include, without limitation, amounts received in connection with the delivery or sale of Shares of such Restricted Stock or cash paid in respect of any Restricted Stock.

There shall be no forfeiture or repayment under Section 10(b) following a Change-in-Control.

(d) The Board, in its discretion, shall determine whether a Participant's conduct, activities or circumstances constitute events described in Section 10(b) and whether and to what extent the Shares of Restricted Stock awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Section 10(c). The Board shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant's outstanding Shares of Restricted Stock pending an investigation of a bona fide dispute regarding Participant's eligibility to receive a payment under the terms of this Agreement as determined by the Board in good faith.

(e) For purposes of applying this provision:

(i) "Cause" means any of the following:

(u) a Participant's violation of his or her material duties to the Company or any of its affiliates, which continues after written notice from the Company or any affiliate to cure such violation;

(v) Participant's willful failure to follow the lawful written directives of the Board in any material respect;

(w) Participant's willful misconduct in connection with the performance of any of his or her duties, including but not limited to falsifying or attempting to falsify documents, books or records of the Company or any of its affiliates, making or delivering a false representation, statement or certification of compliance to the Company, misappropriating or attempting to misappropriate funds or other property of the Company or any of its affiliates, or securing or attempting to secure any personal profit in connection with any transaction entered into on behalf of the Company or any of its affiliates;

(x) Participant's breach of any material provisions of this Agreement or any other non-competition, non-interference, non-disclosure, confidentiality or other similar agreement executed by Participant with the Company or any of its affiliates;

(y) conviction (or plea of *nolo contendere*) of the Participant of any felony, or a misdemeanor involving false statement, in connection with conduct involving the Company or any of its subsidiaries or affiliates; or

(z) intentional engagement in any activity which would constitute or cause a breach of duty of loyalty, or any fiduciary duty to the Company or any of its subsidiaries or affiliates.

(ii) "Code of Conduct" means any code of ethics or code of conduct now or hereafter adopted by the Company or any of its affiliates, including to the extent applicable the Company's Employee Conduct and Disclosure Policy dated November 22, 1999, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies and Procedures, as amended, supplemented or replaced from time to time.

(f) Participant agrees that the provisions of this Section 10 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Section 10, the Company would not have entered into this Agreement.

11. **Transferability**. This Restricted Stock is not transferable by the Participant, whether voluntarily or involuntarily, by operation of laws or otherwise, during the Restriction Period, except as provided in the Plan. If any assessment, pledge, transfer, or other disposition, voluntary or involuntary, of this Restricted Stock shall be made, or if any attachment, execution, garnishment, or claim shall be issued against or placed upon the Restricted Stock, then the Participant's right to the Restricted Stock shall immediately cease and terminate and the Participant shall promptly forfeit to the Company all Restricted Stock awarded under this Agreement.

12. **Tax Treatment**. The following is a brief summary of the principal federal income tax consequences related to grants of restricted stock. This summary is based on the Company's understanding of present federal income tax law and regulations. The summary does not purport to be complete or applicable to every specific situation.

The value of restricted stock granted to the Participant will be taxable to the Participant in the year in which it is no longer subject to substantial risk of forfeiture (i.e., when the restrictions lapse). When the restrictions lapse, there is an ordinary income tax event to the Participant equal to the number of shares multiplied by the market price of the shares at the time the restrictions lapse. The Participant must satisfy federal and state withholding requirements and may do so by having the Company sell sufficient shares to meet the withholding requirements.

The Participant has the option to make a Code Section 83(b) election on a grant of restricted stock. Code Section 83(b) allows the Participant to choose to be taxed immediately on the amounts received in connection with a substantially "nonvested" right (i.e., compensation that has not been constructively received). This is accomplished by the Participant filing an election with the IRS stating that he or she will pay ordinary income on the value as measured at the time of grant. Any future appreciation in the stock property will be treated as capital gain when sold. This election must be made within 30 days of the Date of Grant.

If the Participant elects Section 83(b) treatment and later forfeits the subject stock, he or she will not be entitled to any refund for the taxes paid; however, he or she will be entitled to treat the forfeiture as a sale of the stock at a loss (i.e., capital loss) *(limited to the amount paid for shares--typically zero).*

13. **Withholding**.

Tax Withholding. The Company shall have the power and the right to deduct or withhold, or require the Participant to remit to the Company, an amount sufficient to satisfy federal, state and local taxes (including Participant's FICA obligation), domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of this Plan.

Share Withholding. With respect to withholding required upon the lapse of restrictions or upon any other taxable event arising as a result of the Awards granted hereunder, the Participants may elect, subject to the approval of the Board, to satisfy the withholding requirement, in whole or in part, by having the Company withhold shares having a Fair Market Value on the date the tax is to be determined equal to the minimum statutory total tax that could be imposed on the transaction. All such elections shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

14. **Requirements of Law**. The issuance of Shares under the Plan shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

15. **Inability to Obtain Authorization**. The inability of the Company to obtain authority from any regulatory body having jurisdiction, which authority is deemed by the Company's counsel to be necessary to the lawful issuance of any Shares hereunder, shall relieve the Company of any liability in respect of the failure to issue such Shares as to which such requisite authority shall not have been obtained.

16. **Severability**. In the event any provision of this Agreement shall be held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Agreement, and the Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

17. **Continuation of Employment**. This Agreement shall not confer upon the Participant any right to continuation of employment by the Company, nor shall this Agreement interfere in any way with the Company's right to terminate the Participant's employment at any time, for any reason. Participant further agrees that awards made pursuant to this Agreement are discretionary, and do not constitute a benefit which the Company is obligated to make available to Participant, and therefore, nothing in this Agreement shall be deemed to constitute a contract of employment, or otherwise alter the at-will employment relationship between Participant and the Company.

18. **Applicable Laws and Consent to Jurisdiction**. The validity, construction, interpretation and enforceability of this Agreement shall be determined and governed by the laws of the State of South Dakota without giving effect to the principles of conflicts of law. For the purpose of litigating any dispute that arises under this Agreement, the parties hereby consent to exclusive jurisdiction in South Dakota and agree that such litigation shall be conducted in the courts of Pennington County or the federal courts of the United States for the District of South Dakota, Western Division.

19. **Miscellaneous**. The Plan may be amended at any time, and from time to time, by a written instrument approved by the Board of Directors of Black Hills Corporation. No termination, amendment or modification of the Plan shall adversely affect in any material way any Award previously granted under the Plan, without the written consent of the Participant holding such Award, except as required by law.

    The Plan and this Agreement are binding upon Participant, as well as his/her heirs, executors, personal representatives, trustees, attorneys, agents, administrators, and successors.

Please refer any questions you may have regarding your restricted stock to Roxann R. Basham, Vice President Governance and Corporate Secretary. Once again, congratulations on receipt of your restricted stock.

Sincerely,

____

Roxann R. Basham
Vice President Governance and Corporate Secretary

Please acknowledge your agreement to participate in the Plan and this Agreement, and to abide by all of the governing terms and provisions, by signing the following representation:

Agreement to Participate

By signing a copy of this Agreement and returning it to Roxann R. Basham, Vice President Governance and Corporate Secretary of Black Hills Corporation, I acknowledge that I have read the Plan, and that I fully understand all of my rights under the Plan, as well as all of the terms and conditions which may limit my eligibility to exercise this Award. Without limiting the generality of the preceding sentence, I understand that my right to exercise this Award is conditioned upon my continued employment with Black Hills Corporation or its Subsidiaries.

____

Exhibit 10.17

Black Hills Corporation
2005 Omnibus Incentive Plan
Restricted Stock Unit Agreement
(Effective for Awards granted on or after January 1, 2009)

Dear ________________________**:**

Congratulations on your award under the Black Hills Corporation 2005 Omnibus Incentive Plan (the "Omnibus Plan") and your participation in the Black Hills Corporation Nonqualified Deferred Compensation Plan (the "NDC Plan") (collectively, the "Plans"). This Agreement and the Plans together govern your rights to the award and set forth all of the conditions and limitations affecting such rights. Copies of the Plans have been delivered to you. All capitalized terms shall have the meanings ascribed to them in the respective Plan unless specifically set forth otherwise herein. If there is any inconsistency between the terms of this Agreement and the terms of the Plans, the Plans' terms shall supersede and replace the conflicting terms of this Agreement. By signing below, you agree to be bound by all the provisions of the Plans and this Agreement.

Overview of Your Award.

1. **Number of Restricted Stock Units Granted.** _______ Restricted Stock Units ("RSUs"), each unit corresponding to one share of Black Hills Corporation Common Stock. Each RSU constitutes only an unsecured promise of the Company to deliver a share of Common Stock to the Participant under the terms of the NDC Plan. As a holder of RSUs, the Participant has only the rights of a general unsecured creditor of the Company.

2. **Date of Grant.** _____________

3. **Date of Vesting.** Subject to continued employment under Section 4 below, the RSUs shall vest and become nonforfeitable in accordance with the following schedule (each date is a "Vesting Date"):

Shares	Date
_____	_______
_____	_______
_____	_______

4. **Employment by the Company.** This Restricted Stock Unit Award is conditioned on the Participant's remaining as an employee of Black Hills Corporation and its Affiliates (the "Company") from the Date of Grant through (and including) the Vesting Dates. The Award of these RSUs, however, shall not impose upon the Company any obligations to retain the Participant in its employ for any given period or upon any specific terms of employment.

5. **Termination of Employment by Reasons of Death or Disability, and Vesting in Connection with a Change in Control.** In the event the Participant's employment is terminated by reason of Death or Disability, or in the event of a Change in Control prior to any one of the Vesting Dates, all RSUs then unvested and outstanding shall immediately vest one hundred percent (100%), and, as soon as is administratively practicable, the awards shall be settled in accordance with Section 7.

"Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any of the following events:

(a) The acquisition in a transaction or series of transactions within a 12 month period by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Agreement, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c)(i), (ii) and (iii), below;

(b) Individuals who, as of December 31, 2007 are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least a majority of the members of the Board within a 12 month period; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest;

(c) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company and/or its subsidiaries, or a sale or other disposition (whether by sale, taxable or non-taxable exchange, formation of a joint venture or otherwise) of fifty percent (50%) or more of the assets of the Company and/or its subsidiaries (each a "Business Combination"), unless, in each case, immediately following such Business Combination, (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more that fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one (1) or more subsidiaries)(the "Successor Entity"); (ii) no Person (excluding any Successor entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c) (i), (ii), and (iii) above.

(e) A Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common Stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding Common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(f) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

Notwithstanding the above provisions of this definition, to the extent that any payment under the Agreement due to a Change in Control is subject to Code Section 409A for deferred compensation, then the term Change in Control shall be construed in a manner that is consistent with Code Section 409A(a)(2)(A)(v), but only to the extent inconsistent with the above provisions as determined by the Board.

6. **Forfeiture and Repayment.**

(a) In the event the Participant's employment is terminated for reasons other than those described in Section 5 herein prior to the Vesting Dates, then all outstanding RSUs granted hereunder that are unvested shall immediately be forfeited by the Participant.

(b) Without limiting the generality of Section 6(a), the Company reserves the right to cancel all Restricted Stock Units awarded hereunder, whether or not vested, and require the Participant to repay all income or gains previously realized in respect of such Restricted Stock Units, in the event of the occurrence of any of the following events:

- termination of Participant's employment for Cause;

- within one year following any termination of Participant's employment, the Board determines that the Participant engaged in conduct before the Participant's termination date that would have constituted the basis for a termination of employment for Cause;

- at any time during the Participant's employment or the twelve month period immediately following any termination of employment, Participant:

  (x) publicly disparages the Company, any of its affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

  (y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct; or

- Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Board determines that the Participant's conduct, activities or circumstances constitute events described in Section 6(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

- cancel any Restricted Stock Units awarded hereby, whether or not vested; and/or

- require the Participant to repay an amount equal to all income or gain realized in respect of all such Restricted Stock Units. The amount of repayment shall include, without limitation, amounts received in connection with the delivery or sale of Shares associated with such Restricted Stock Units or cash paid in respect of any Restricted Stock Units.

There shall be no forfeiture or repayment under Section 6(b) following a Change-in-Control.

(d) The Board, in its discretion, shall determine whether a Participant's conduct, activities or circumstances constitute events described in Section 6(b) and whether and to what extent the Shares or Restricted Stock Units awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Section 6(c). The Board shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant's outstanding Shares or Restricted Stock Units pending an investigation of a bona fide dispute regarding Participant's eligibility to receive a payment under the terms of this Agreement as determined by the Board in good faith.

(e) For purposes of applying this provision:

(i) "Cause" means any of the following:

(u) a Participant's violation of his or her material duties to the Company or any of its affiliates, which continues after written notice from the Company or any affiliate to cure such violation;

(v) Participant's willful failure to follow the lawful written directives of the Board in any material respect;

(w) Participant's willful misconduct in connection with the performance of any of his or her duties, including but not limited to falsifying or attempting to falsify documents, books or records of the Company or any of its affiliates, making or delivering a false representation, statement or certification of compliance to the Company, misappropriating or attempting to misappropriate funds or other property of the Company or any of its affiliates, or securing or attempting to secure any personal profit in connection with any transaction entered into on behalf of the Company or any of its affiliates;

(x) Participant's breach of any material provisions of this Agreement or any other non-competition, non-interference, non-disclosure, confidentiality or other similar agreement executed by Participant with the Company or any of its affiliates;

(y) conviction (or plea of *nolo contendere*) of the Participant of any felony, or a misdemeanor involving false statement, in connection with conduct involving the Company or any of its subsidiaries or affiliates; or

(z) intentional engagement in any activity which would constitute or cause a breach of duty of loyalty, or any fiduciary duty to the Company or any of its subsidiaries or affiliates.

(ii) "Code of Conduct" means any code of ethics or code of conduct now or hereafter adopted by the Company or any of its affiliates, including to the extent applicable the Company's Employee Conduct and Disclosure Policy dated November 22, 1999, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies and Procedures, as amended, supplemented or replaced from time to time.

(f) Participant agrees that the provisions of this Section 6 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Section 6, the Company would not have entered into this Agreement.

7. **Settlement of RSU Award.**

Settlement. The Company shall credit to Participant's Account under the NDC Plan (or any successor Plan that may be adopted by the Company) as soon as practicable following the execution of this Agreement, the number of units specified above; provided, however, that any RSUs deferred remain subject to (a) the relevant Vesting Date for such portion of the Award and (b) any cancellation of the RSUs pursuant to Section 6. If the RSU does not vest, the deferral into the NDC Plan shall be null and void. The form and timing of payment with respect to any vested RSU shall be made pursuant to the terms and conditions of the NDC Plan.

Dividend and Stock Split Equivalents. For so long as Participant holds RSUs in his or her Account under the NDC Plan, at the time any dividend is paid with respect to a share of Common Stock or any forward stock split occurs, the Company shall pay to Participant on the same date (or as soon as practicable thereafter) in respect of each RSU held by the Participant as of the record date for such dividend or split an amount at the Company's sole, absolute and unfettered discretion, in cash, Common Stock, or other property, or in a combination thereof, in each case having a value equal to the dividend or split. Such amounts shall vest and shall be paid at the same time as the underlying RSU award is settled.

8. **Beneficiary Designation.** The Participant may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit under this Agreement and the NDC Plan is to be paid. The designation of a beneficiary shall be made in accordance with the beneficiary designation procedures specified in the NDC Plan.

9. **Transferability.** The RSUs are not transferable by the Participant, whether voluntarily or involuntarily, by operation of laws or otherwise. If any assessment, pledge, transfer, or other disposition, voluntary or involuntary, of the RSUs shall be made, or it any attachment, execution, garnishment, or claim shall be issued against or placed upon the RSUs, then the Participant's right to the RSUs shall immediately cease and terminate and the Participant shall promptly forfeit to the Company all RSUs awarded under this Agreement.

10. **Withholding.** The Company shall have the power and the right to deduct or withhold, or require the Participant to remit to the Company, an amount sufficient to satisfy federal, state and local taxes (including Participant's FICA obligation), domestic or foreign, required by law or regulation to be withheld with respect to any taxable event arising as a result of this Agreement as specified under the NDC Plan.

11. **Requirements of Law.** The issuance of Shares under the Plans following settlement of the RSUs shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

12. **Inability to Obtain Authorization.** The inability of the Company to obtain authority from any regulatory body having jurisdiction, which authority is deemed by the Company's counsel to be necessary to the lawful issuance of any Shares hereunder, shall relieve the Company of any liability in respect of the failure to issue such Shares as to which such requisite authority shall not have been obtained.

13. **Severability.** In the event any provision of this Agreement shall be held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Agreement, and the Agreement shall be construed and enforced as if the illegal or invalid provision had not been included.

14. **Continuation of Employment.** This Agreement shall not confer upon the Participant any right to continuation of employment by the Company, nor shall this Agreement interfere in any way with the Company's right to terminate the Participant's employment at any time, for any reason. Participant further agrees that awards made pursuant to this Agreement are discretionary, and do not constitute a benefit which the Company is obligated to make available to Participant, and therefore, nothing in this Agreement shall be deemed to constitute a contract of employment, or otherwise alter the at-will employment relationship between Participant and the Company.

15. **Applicable Laws and Consent to Jurisdiction.** The validity, construction, interpretation and enforceability of this Agreement shall be determined and governed by the laws of the State of South Dakota without giving effect to the principles of conflicts of law. For the purpose of litigating any dispute that arises under this Agreement, the parties hereby consent to exclusive jurisdiction in South Dakota and agree that such litigation shall be conducted in the courts of Pennington County or the federal courts of the United States for the District of South Dakota, Western Division.

16. **Miscellaneous.** The Plans may be amended at any time, and from time to time, by a written instrument approved by the Board of Directors of Black Hills Corporation. No termination, amendment or modification of the Plans shall adversely affect in any material way any Award previously granted under the Plans, without the written consent of the Participant holding such Award, except as required by law.

    The Plans and this Agreement are binding upon Participant, as well as his/her heirs, executors, personal representatives, trustees, attorneys, agents, administrators, and successors.

17. **Six Month Delay.** Notwithstanding any provision in this Agreement to the contrary, if the payment of any benefit under the NDC Plan that was credited pursuant to this Agreement would be subject to additional taxes and interest under Code Section 409A because the timing of such payment is not delayed as provided in Section 409A for a "specified employee" (within the meaning of Section 409A), then if the Executive is a "specified employee", any such payment that the executive would otherwise be entitled to receive during the first six months following the date off termination of employment shall be accumulated and paid or provided, as applicable, within sixty (60) days after the date, that is six months following the date of termination of employment, or such earlier date upon which such amount can be paid or provided under Section 409A without being subject to such additional taxes and interest such as, for example, upon the death of Participant.

Please refer any questions you may have regarding your RSU award to Roxann R. Basham, Vice President Governance and Corporate Secretary. Once again, congratulations on receipt of your award.

Sincerely,

Please acknowledge your agreement to participate in the Plans and this Agreement, and to abide by all of the governing terms and provisions, by signing the following representation:

Agreement to Participate

> By signing a copy of this Agreement and returning it to Roxann R. Basham, Vice President Governance and Corporate Secretary of Black Hills Corporation, I acknowledge that I have read the Plans, and that I fully understand all of my rights under the Plans, as well as all of the terms and conditions which may limit my eligibility to exercise this Award. Without limiting the generality of the preceding sentence, I understand that my right to exercise this Award is conditioned upon my continued employment with Black Hills Corporation or its Subsidiaries.

____

Exhibit 10.19

Black Hills Corporation
Incentive Compensation Plan
Performance Share Award Agreement
(Effective for Plans beginning on or after January 1, 2009)
Performance Period __________________________

Contents

Black Hills Corporation
2005 Omnibus Incentive Plan
Performance Share Award Agreement
(Effective for Plans beginning on or after January 1, 2009)

Performance Period ________________________________

You have been selected to be a participant in the Black Hills Corporation 2005 Omnibus Incentive Plan (the "Plan"), as specified below:

Participant: _____________________

Target Performance Share Award: ______ shares

Performance Period: ______________________________

Performance Measure: Total Shareholder Return ("TSR").

Peer Index:

AGL Resources Inc.	ATG	Otter Tail Corp	OTTR
ALLETE Inc.	ALE	PNM Resources, Inc.	PNM
Avista Corp	AVA	Portland General Electric Co.	POR
CH Energy Group Inc.	CHG	Puget Energy Inc.	PSD
Cleco Corp	CNL	NV Energy, Inc.	NVE
DPL Inc.	DPL	UIL Holdings Corp	UIL
Great Plains Energy Inc.	GXP	UniSource Energy Corp	UNS
IDACORP Inc.	IDA	Vectren Corp	VVC
MDU Resources Group Inc.	MDU	Westar Energy Inc.	WR
NorthWestern Corp	NWEC	WGL Holdings Inc.	WGL

THIS AGREEMENT (the "Agreement") effective _____________, represents the grant of Performance Shares by Black Hills Corporation, a South Dakota corporation (the "Company"), to the Participant named above, pursuant to the provisions of the Plan.

The Plan provides a complete description of the terms and conditions governing the Performance Shares. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall completely supersede and replace the conflicting terms of this Agreement.

All capitalized terms shall have the meanings ascribed to them in the Plan, unless specifically set forth otherwise herein.

The parties hereto agree as follows:

Article 1. Performance Period

The Performance Period commences on ____________ and ends on _______________.

Article 2. Value of Performance Shares

Each Performance Share shall represent and have a value equal to one share of common stock of the Company.

Notwithstanding anything herein to the contrary, the Performance Shares shall have no value whatsoever if the Ending Stock Price (as defined herein) is not greater than Beginning Stock Price (as defined herein), taking into account any adjustments made pursuant to Paragraph 4.4 of the Plan.

Article 3. Performance Shares and Achievement of Performance Measure

(a) The number of Performance Shares to be earned under this Agreement shall be based upon the achievement of pre-established TSR performance goals as set by the Compensation Committee of the Board of Directors (Committee) for the Performance Period, based on the following chart:

TSR Performance Relative to Companies in Peer Index	Payout (% of Target)
80^{th} Percentile or Above	175%
70^{th} Percentile	150%
60^{th} Percentile	125%
50^{th} Percentile	100%
40^{th} Percentile	50%
Below the 40^{th} Percentile	0%

Interpolation shall be used to determine the percentile rank in the event the Company's Percentile Rank does not fall directly on one of the ranks listed in the above chart.

For this purpose, Total Shareholder Return shall be determined as follows:

$$\text{Total Shareholder Return} = \frac{\text{Change in Stock Price + Dividends Paid}}{\text{Beginning Stock Price}}$$

Beginning Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the twenty (20) trading days immediately prior to the first day of the Performance Period; Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the twenty (20) trading days immediately prior to the last day of the Performance Period; Change in Stock Price shall mean the difference between the Beginning Stock Price and the Ending Stock Price; and Dividends Paid shall mean the total of all dividends paid on one (1) share of stock during the Performance Period.

Following the Total Shareholder Return determination, the Company's Percentile Rank shall be determined as follows:

Percentile Rank shall be determined by listing from highest Total Shareholder Return to lowest Total Shareholder Return each company in the Peer Index (excluding the Company). The top company would have a one hundred percentile (100%) rank and the bottom company would have a zero percentile (0.0%) rank. Each company in between would be one hundred divided by n minus one (100/(n-1)) above the company below it, where "n" is the total number of companies in the Peer Index. The Company percentile rank would then be interpolated based on the Company TSR. The Companies in the Peer Index shall remain constant throughout the entire Performance Period.

Article 4. Termination Provisions

Except as provided below in this Article 4 and in Article 5, a Participant shall be eligible for payment of awarded Performance Shares, as determined in Article 3, only if the Participant's employment with the Company continues through the end of the Performance Period.

If participant retires, suffers a Disability, or dies during the Performance Period, the Participant (or the Participant's estate) shall be entitled to that proportion of the number of Performance Shares as such Participant is entitled to under Article 3 for such Performance Period that the number of full months of participation during the Performance Period bears to the total number of months in the Performance Period. The form and timing of the payment of such Performance Shares shall be as set forth in Article 8.

"Separation from service" (as defined in Treasury Regulation Section 1.409A-1(h)) during the Performance Period other than (i) due to Retirement, Disability, or death, or (ii) following a Change in Control shall require forfeiture of this entire award, with no payment to the Participant.

Article 5. Change in Control

Notwithstanding anything herein to the contrary, in the event of a Change in Control, the Participant shall be entitled to that proportion of the number of Performance Shares as such Participant is entitled to under Article 3 for such Performance Period that the number of full months of participation during the Performance Period (as of the effective date of the Change in Control) bears to the total number of months in the Performance Period. When there is a Change in Control, the TSR shall be calculated as set forth in Article 3, except that the Ending Stock Price shall mean the average closing price on the applicable stock exchange of one share of stock for the twenty (20) trading days immediately prior to the Change in Control. Performance Shares shall be paid out to the Participant in cash within thirty (30) days of the effective date of the Change in Control.

"Change in Control" of the Company shall be deemed to have occurred (as of a particular day, as specified by the Board) upon the occurrence of any of the following events:

(a) The acquisition in a transaction or series of transactions within a 12 month period by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Agreement, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c) (i), (ii) and (iii), below;

(b) Individuals who, as of December 31, 2007 are members of the Board (the "Incumbent Board"), cease for any reason to constitute at least a majority of the members of the Board within a 12 month period; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "Proxy Contest") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest;

(c) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company and/or its subsidiaries, or a sale or other disposition (whether by sale, taxable or non-taxable exchange, formation of a joint venture or otherwise) of fifty percent (50%) or more of the assets of the Company and/or its subsidiaries (each a “Business Combination”), unless, in each case, immediately following such Business Combination, (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more that fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company’s assets either directly or through one (1) or more subsidiaries)(the “Successor Entity”); (ii) no Person (excluding any Successor Entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c) (i), (ii), and (iii) above.

(e) A Change in Control shall not be deemed to occur solely because any Person (the "Subject Person") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common Stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Persons, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding Common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(f) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

Notwithstanding the above provisions of this definition, to the extent that any payment under the Agreement due to a Change in Control is subject to Code Section 409A for deferred compensation, then the term “Change in Control” shall be construed in a manner that is consistent with Code Section 409A(a)(2)(A)(v), but only to the extent inconsistent with the above provisions as determined by the Board.

Article 6. Forfeiture and Repayment.

(a) In the event the Participant incurs a separation from service for a reason other than those described in Article 4 herein during the Performance Period this entire award will be forfeited, unless the separation from service follows a Change in Control.

(b) Without limiting the generality of Article 6(a), the Company reserves the right to cancel all Performance Shares awarded hereunder, whether or not vested, and require the Participant to repay all income or gains previously realized in respect of such Performance Shares, in the event of the occurrence of any of the following events:

(i) termination of Participant’s employment for Cause;

(ii) within one year following any termination of Participant’s employment, the Board determines that the Participant engaged in conduct before the Participant’s termination date that would have constituted the basis for a termination of employment for Cause;

(iii) at any time during the Participant’s employment or the twelve month period immediately following any termination of employment, Participant:

(x) publicly disparages the Company, any of its affiliates or any of its or their officers, directors or senior executive employees or otherwise makes any public statement that is materially detrimental to the interests or reputation of the Company, any of its affiliates or such individuals; or

(y) violates in any material respect any policy or any code of ethics or standard of behavior or conduct generally applicable to Participant, including the Code of Conduct; or

(iv) Participant engages in any fraudulent, illegal or other misconduct involving the Company or any of its affiliates, including but not limited to any breach of fiduciary duty, breach of a duty of loyalty, or interference with contract or business expectancy.

(c) If the Board determines that the Participant’s conduct, activities or circumstances constitute events described in Article 6(b), in addition to any other remedies the Company has available to it, the Company may in its sole discretion:

(i) cancel any Performance Shares awarded hereby, whether or not issued; and/or

(ii) require the Participant to repay an amount equal to all income or gain realized in respect of all such Performance Shares. The amount of repayment shall include, without limitation, amounts received in connection with the delivery or sale of Shares of such Performance Shares or cash paid in respect of any Performance Shares.

There shall be no forfeiture or repayment under Article 6(b) following a Change-in-Control.

(d) The Board, in its discretion, shall determine whether a Participant’s conduct, activities or circumstances constitute events described in Article 6(b) and whether and to what extent the Performance Shares awarded hereby shall be forfeited by Participant and/or a Participant shall be required to repay an amount pursuant to Article 6(c). The Board shall have the authority to suspend the payment, delivery or settlement of all or any portion of such Participant’s outstanding Performance Shares pending an investigation of a bona fide dispute regarding Participant’s eligibility to receive a payment under the terms of this Agreement as determined by the Board in good faith.

(e) For purposes of applying this provision:

(i) “Cause” means any of the following:

(u) a Participant's violation of his or her material duties to the Company or any of its affiliates, which continues after written notice from the Company or any affiliate to cure such violation;

(v) Participant's willful failure to follow the lawful written directives of the Board in any material respect;

(w) Participant's willful misconduct in connection with the performance of any of his or her duties, including but not limited to falsifying or attempting to falsify documents, books or records of the Company or any of its affiliates, making or delivering a false representation, statement or certification of compliance to the Company, misappropriating or attempting to misappropriate funds or other property of the Company or any of its affiliates, or securing or attempting to secure any personal profit in connection with any transaction entered into on behalf of the Company or any of its affiliates;

(x) Participant's breach of any material provisions of this Agreement or any other non-competition, non-interference, non-disclosure, confidentiality or other similar agreement executed by Participant with the Company or any of its affiliates;

(y) conviction (or plea of *nolo contendere*) of the Participant of any felony, or a misdemeanor involving false statement, in connection with conduct involving the Company or any of its subsidiaries or affiliates; or

(z) intentional engagement in any activity which would constitute or cause a breach of duty of loyalty, or any fiduciary duty to the Company or any of its subsidiaries or affiliates.

(ii) "Code of Conduct" means any code of ethics or code of conduct now or hereafter adopted by the Company or any of its affiliates, including to the extent applicable the Company's Employee Conduct and Disclosure Policy dated November 22, 1999, as amended or supplemented from time to time, and the Company's or subsidiary Risk Management Policies and Procedures, as amended, supplemented or replaced from time to time.

(f) Participant agrees that the provisions of this Article 6 are entered into in consideration of, and as a material inducement to, the agreements by the Company herein as well as an inducement for the Company to enter into this Agreement, and that, but for Participant's agreement to the provisions of this Article 6, the Company would not have entered into this Agreement.

Article 7. Dividends

During the Performance Period, all dividends and other distributions paid with respect to the shares of Common Stock shall accrue for the benefit of the Participant to be paid out to the Participant pursuant to Article 8.

Article 8. Form and Timing of Payment of Performance Shares

Payment of the Performance Shares, including accrued dividends, shall be made fifty percent (50%) in cash and fifty percent (50%) in shares of Company stock.

Payment of Performance Shares shall be made within sixty (60) calendar days following the close of the Performance Period, subject to the following:

(a) The Participant shall have no right with respect to any Award or a portion there of, until such award shall be paid to such Participant.

(b) If the Committee determines, in its sole discretion, that a Participant at any time has willfully engaged in any activity that the Committee determines was or is harmful to the Company, any unpaid pending Award will be forfeited by such Participant.

(c) All appropriate taxes will be withheld from the cash portion of the award.

Article 9. Nontransferability

Performance Shares may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. Further, except as otherwise provided in a Participant's Award Agreement, a Participant's rights under the Plan shall be exercisable during the Participant's lifetime only by the Participant or the Participant's legal representative.

Article 10. Administration

This Agreement and the rights of the Participant hereunder are subject to all the terms and conditions of the Plan, as the same may be amended from time to time by the Board of Directors, as well as to such rules and regulations as the Committee may adopt for administration of the Plan. It is expressly understood that the Committee is authorized to administer, construe, and make all determinations necessary or appropriate to the administration of the Plan and this Agreement, in its sole discretion, all of which shall be binding upon the Participant.

Any inconsistency between the Agreement and the Plan shall be resolved in favor of the Plan.

Article 11. Miscellaneous

(a) The selection of any employee for participation in the Plan shall not give such Participant any right to be retained in the employ of the Company. The right and power of the Company to dismiss or discharge any Participant at-will, is specifically reserved. Such Participant or any person claiming under or through the Participant shall not have any right or interest in the Plan or any Award thereunder, unless and until all terms, conditions, and provisions of the Plan that affect such Participant have been complied with as specified herein.

(b) With the approval of the Board, the Committee may terminate, amend, or modify the Plan; provided, however, that no such termination, amendment, or modification of the Plan may in any way adversely affect the Participant’s rights under this Agreement without the Participant’s written consent, except as required by law.

(c) Participant shall not have voting rights with respect to the Performance Shares. Participant shall obtain voting rights upon the settlement of Performance Shares and distribution into shares of common stock of the Company.

(d) The Participant may defer such Participant’s receipt of the payment of cash and the delivery of shares of common stock, that would otherwise be due to such Participant by virtue of the satisfaction of the performance goals with respect to the Performance Shares, pursuant to the rules of the Black Hills Corporation Nonqualified Deferred Compensation Plan and the procedures set forth by the Compensation Committee. If the Participant elects to defer the receipt of the award, the Participant will be required to pay any necessary taxes from their own funds. They will not be allowed to have their deferred award reduced for tax withholding.

(e) This Agreement shall be subject to all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

(f) To the extent not preempted by federal law, this Agreement shall be governed by, and construed in accordance with, the laws of the State of South Dakota.

(g) Any awards received by Participant are subject to the provisions of the Stock Ownership Guidelines approved by the Board of Directors.

The following parties have caused this Agreement to be executed effective as of ________________.

Black Hills Corporation

By: _______________________

____
Participant

THE OUTSIDE DIRECTORS

STOCK BASED COMPENSATION PLAN

(As amended and restated effective January 1, 2009)

The Outside Directors Stock Based Compensation Plan ("Plan") is hereby amended and restated by Black Hills Corporation ("Company") effective the 1st day of January, 2009, except as otherwise noted herein. **[NOTE: provision permitting reelections in 2008 is effective before January 1, 2009.]**

1. RECITALS.

This document is an amendment and restatement of the Plan which was adopted by the Company effective the 1st day of January, 1997. The Plan was established to provide to Participants certain benefits in order to attract and retain competent and hardworking outside directors whose abilities, experience and judgment can contribute to the well-being of the Company and its shareholders and to further align the long-term interests of the outside directors with those of the shareholders by providing benefits based on Company common stock equivalents.

Under Section 11 of the Plan, the Company reserved the right to amend, modify, or discontinue the Plan provided only that any modification does not reduce accrued and unpaid benefits.

The purpose of this amendment and restatement is to incorporate Plan amendments adopted since 1997 and to bring the Plan into compliance with the requirements of Section 409A of the Internal Revenue Code and the final regulations thereunder effective January 1, 2009. The Plan has been operated in good faith compliance with the requirements of Section 409A of the Internal Revenue Code and the interim guidance issued thereunder during the period beginning January 1, 2005 and ending December 31, 2008. The Company does not intend to "grandfather" any benefits earned and vested under the Plan as of December 31, 2004. The amendment and restatement does not reduce any accrued and unpaid benefits.

2. PARTICIPANTS.

Each Outside Director of the Company shall become a Participant in the Plan on the date he or she becomes an Outside Director and shall remain a Participant until his or her entire Account has been distributed. Notwithstanding the foregoing, no Company common stock equivalents shall be added to the Participant's Account with respect to any Quarter Period beginning after the Participant ceases to be an Outside Director of the Company.

3. ESTABLISHMENT OF ACCOUNTS..

The Company shall establish an Account for each Participant. As of the last day of each Quarter Period ending after the Participant enters the Plan and on or before the Participant's Benefit Payment Date, the Participant's Account shall be credited with the Participant's share of Company common stock equivalents, including fractional equivalents, for the Quarter Period, as determined in accordance with Section 4. If the Participant's Benefit Payment Date occurs on a date other than the last day of a Quarter Period, the Participant's Account shall be credited with the appropriate amount of Company common stock equivalents, if any, for the Quarter Period in which the Benefit Payment Date occurs. In addition, the Participant's Account shall be adjusted, as appropriate, to reflect stock splits, cash dividends, stock dividends, merger, consolidation and similar circumstances affecting the Company common stock. Cash dividends will be added in the form of common stock equivalents.

4. ADDITIONS TO ACCOUNTS.

a. Additions to Accounts for periods prior to December 1, 2007 are under the Plan as in effect prior to January 1, 2009.

b. For the Quarter Period December 1, 2007 through February 29, 2008, each Participant shall be entitled to a quarterly addition to their Account in the amount determined by dividing the sum of $11,333.33 by the market price of the Company common stock on February 29, 2008. For the Quarter Period beginning March 1, 2008, and for the remainder of the Plan year, and for each Plan year thereafter, each Participant shall be entitled to a quarterly addition to his or her Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $12,500 by the market price of the Company common stock on the last day of the Quarter Period for each Quarter Period of the Plan Year that the Participant is eligible for benefits. If a Participant is not an Outside Director for the entire Quarter Period, then the Participant's addition for the quarter should be prorated for the number of days that the Participant served as Outside Director.

5. TIME AND MANNER OF BENEFIT PAYMENTS.

a. Each Participant who entered the Plan before 2009 and whose Benefit Payment Date is after December 31, 2008 may elect a new Benefit Payment Date on an election form to be filed with the Committee. Such Benefit Payment Date shall be the first day of the month beginning after the later of (1) the date the Participant Separates from Service and (2) the date the Participant attains a specified age, provided that such age is at least 60 and no greater than 70. The election must be made in writing no later than December 31, 2008 in accordance with procedures established by the Committee, and shall in no case cause payment to occur in the year in which such election is made. If such Participant fails to make an election by December 31, 2008, his prior election shall remain in effect, provided that such prior election is not inconsistent with the provisions of the Plan as in effect on January 1, 2009. If there is no prior election, or if the prior election is inconsistent with the terms of the Plan as in effect on January 1, 2009, the “default” provisions of this Section shall apply.

Participants entering the Plan for the first time after December 31, 2008 may also elect a Benefit Payment Date. Such Benefit Payment Date shall be the first day of the month beginning after the later of (1) the date the Participant Separates from Service and (2) the date the Participant attains a specified age, provided that such age is at least 60 and no greater than 70. Any election must be made in writing no later than 30 days after the Participant enters the Plan in accordance with procedures established by the Committee, and shall in no case cause payment to occur in the year in which such election is made.. Such election will apply exclusively to quarterly additions made to the Participant’s Account after the election date and the benefit calculation in Section 4(b) will be prorated as if the Participant became an Outside Director on the date of election.

The Benefit Payment Date of a Participant who fails to elect a Benefit Payment Date in accordance with the above shall be the first day of the month beginning after the later of (1) the date the Participant Separates from Service and (2) the date the Participant attains age 60.

b. At the same time and on the same election form described in Section 5a above, the Participant may elect to receive payment of the benefits represented in the Participant’s Account from the following choices:

(1) A lump sum payment in cash or shares of common stock of the Company in an amount equal to the Participant’s Account as of the Benefit Payment Date; or

(2) Payment in monthly installments of cash over a period of not more than 15 years. The first installment is due on the Benefit Payment Date. Subsequent installments shall be paid on the first day of each month thereafter. The installment pay out period shall be specified in the election. The amount of each installment shall equal the balance of the Participant’s Account immediately prior to the installment divided by the number of installments remaining to be paid. After the first installment has been paid, the unpaid Account balance shall accrue interest at an annual rate equal to the United States Treasury Bond yield determined as of the Benefit Payment Date.

A Participant who fails to elect a form of payment in accordance with the above shall receive payment in the form of a cash lump sum in accordance with subsection b(1).

c. The Benefit Payment Date and the payment method, once elected, may only be changed by the Participant’s giving written notice to the Committee of the Participant’s election to change the Benefit Payment Date and payment method and filing such election to change with the Committee; provided, however, that such request shall be made at least one year before the Benefit Payment Date then in effect, shall not become effective for at least one year after the date the request is made, and shall specify a new Benefit Payment Date that is at least five years after the Benefit Payment Date then in effect; and provided further still, that once payments have begun, the form of payment election shall be irrevocable.

A Participant who has elected to receive a lump sum may elect to receive payment in cash or in Company common stock. Such election shall be made in writing prior to the date payment is made in accordance with procedures established by the Committee. In the absence of an election, payment shall be made in cash.

d. Notwithstanding any provision of this Plan to the contrary, if payment of a Key Employee's Account is to be made on account of the Key Employee's Separation from Service, payment to such Key Employee shall begin on the later of (1) the Benefit Payment Date or (2) the first day of the seventh month beginning after the Key Employee's Separation from Service. If payment to a Key Employee is delayed beyond the Benefit Payment Date on account of the provisions of this paragraph, and if payment of the Account is to be made in installments, the first payment shall include a lump sum equal to the sum of the monthly installment payments that would have been made if payment had begun on the Benefit Payment Date.

6. UNFORESEEABLE EMERGENCY.

If a Participant suffers an unforeseeable emergency, as defined herein, the Committee, in its sole discretion, may pay to the Participant that portion of his or her Account which the Committee determines is necessary to satisfy the emergency need, including any amounts necessary to pay any federal, state or local income taxes reasonably anticipated to result from the distribution. A Participant requesting an emergency payment shall apply for the payment in writing on a form approved by the Committee and shall provide such additional information as the Committee may require. For purposes of this Section, "unforeseeable emergency" means a severe financial hardship to the Participant resulting from any of the following:

a. An accident or illness of the Participant or the Participant's spouse, beneficiary or dependent (as defined in Section 152 of the Internal Revenue Code without regard to Section 152(b)(1), (b)(2) or (d)(1)(B) of the Internal Revenue Code);

b. Loss of the Participant's property due to casualty, including the need to rebuild a home following damage not otherwise covered by insurance;

c. Any other similar extraordinary and unforeseeable circumstance that is determined by the Committee, in its sole discretion, to constitute an unforeseen emergency which is not relieved by compensation through insurance or otherwise, and which cannot reasonably be relieved by the liquidation of the Participant's other assets without causing severe financial hardship.

7. PAYMENTS UPON DEATH.

If the Participant dies after payment has begun but before his or her entire Account has been distributed, payment of the remaining Account shall be made to the beneficiary or beneficiaries he or she has designated under Section 9 in the form elected by the Participant. If the Participant dies before payment begins, payment of the Account shall be made to the beneficiary or beneficiaries he or she has designated under Section 9 in a lump sum. The Benefit Payment Date of a lump sum shall be the first day of the month beginning after the Participant's death. Each beneficiary to whom a lump sum is payable may elect to receive payment in cash or in Company common stock. If a lump sum is payable to the Participant's estate, payment shall be in cash or Company common stock, as elected by the personal representative of the Participant's estate. Such election shall be prior to the date payment is made in accordance with procedures prescribed by the Committee.

8. LOSS OF BENEFITS.

Notwithstanding any other provision of the Plan, if a Participant is removed as an Outside Director of the Company because of misconduct or dishonesty, the Participant shall forfeit all right to any benefits payable under this Plan, including vested benefits.

9. DESIGNATION OF BENEFICIARY.

A Participant may designate a beneficiary or beneficiaries to receive benefits after the death of the Participant. The designation shall be effective upon filing written notice with the Committee on the form provided for that purpose. If more than one beneficiary designation has been filed, the beneficiary or beneficiaries designated in the notice bearing the most recent date will be deemed to be the valid beneficiary or beneficiaries. The Participant shall have the right, without the requirement of approval from any person, to revoke and change beneficiary designations. If no valid beneficiary designation has been made, or if all beneficiaries die before a Participant's entire Account has been distributed, payment of the remaining Account will be made to the Participant's estate.

10. PLAN TO BE UNFUNDED.

All benefit payments under the Plan will be made from the general assets of the Company and Participants and their beneficiaries are to be unsecured general creditors of the Company. No special or separate fund is to be established nor other segregation of assets made to create Plan assets or cause the Plan to be a funded plan. Notwithstanding the foregoing, however, the Company may, in its sole discretion, place assets in a trust that may be used to meet Company's obligations under the Plan and any right of a Participant to any benefit payment under the Plan shall be reduced by any payment received by the Participant from the trustee under such a trust. In the event such a trust is established, the assets of such trust shall be available to the general creditors of the Company in the event of the insolvency or bankruptcy of the Company (a "Rabbi trust").

11. PLAN MAY BE MODIFIED OR DISCONTINUED.

The Company reserves the right to amend, modify or discontinue the Plan. Any modification or discontinuance of benefits shall not reduce accrued and unpaid benefits. In addition, any amendment, modification or discontinuance of the Plan shall be consistent with the requirements of Section 409A of the Internal Revenue Code.

12. CHANGE IN CONTROL.

In the event of a Change in Control, as hereafter defined, the Company shall, as soon as possible, but in no event longer than 30 days following the Change of Control, make an irrevocable contribution to the Rabbi trust referred to in Section 10 above, or in the event the Rabbi trust has not been created, shall create such a trust, and make an irrevocable contribution to the trust, in an amount that is sufficient to pay each Participant or beneficiary the benefits to which the Participants or their beneficiaries would be entitled pursuant to the terms of this Plan as of the date of the Change in Control.

For the purposes of this section, the term "Change in Control" shall mean any of the following events:

(1) The acquisition in a transaction or series of transactions by any Person of Beneficial Ownership of thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Company; provided, however, that for purposes of this Plan, the following acquisitions will not constitute a Change in Control: (A) any acquisition by the Company; (B) any acquisition of common stock of the Company by an underwriter holding securities of the Company in connection with a public offering thereof; and (C) any acquisition by any Person pursuant to a transaction which complies with subsections (c)(i), (ii) and (iii);

(2) Individuals who, as of December 31, 2007 are members of the Board (the "**Incumbent Board**"), cease for any reason to constitute at least a majority of the members of the Board; provided, however, that if the election, or nomination for election by the Company's common shareholders, of any new director was approved by a vote of at least two-thirds of the Incumbent Board, such new director shall, for purposes of this Plan, be considered as a member of the Incumbent Board; provided further, however, that no individual shall be considered a member of the Incumbent Board if such individual initially assumed office as a result of either an actual or threatened "Election Contest" (as described in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board (a "**Proxy Contest**") including by reason of any agreement intended to avoid or settle any Election Contest or Proxy Contest; or

(3) Consummation, following shareholder approval, of a reorganization, merger, or consolidation of the Company and/or its subsidiaries, or a sale or other disposition (whether by sale, taxable or non-taxable exchange, formation of a joint venture or otherwise) of fifty percent (50%) or more of the assets of the Company and/or its subsidiaries (each a "**Business Combination**"), unless, in each case, immediately following such Business Combination, (i) all or substantially all of the individuals and entities who were beneficial owners of shares of the common stock of the Company immediately prior to such Business Combination beneficially own, directly or indirectly, more than fifty percent (50%) of the combined voting power of the then outstanding shares of the entity resulting from the Business Combination or any direct or indirect parent corporation thereof (including, without limitation, an entity which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one (1) or more subsidiaries) (the "**Successor Entity**") (ii) no Person (excluding any Successor Entity or any employee benefit plan or related trust, of the Company or such Successor Entity) owns, directly or indirectly, thirty percent (30%) or more of the combined voting power of the then outstanding shares of common stock of the Successor Entity, except to the extent that such ownership existed prior to such Business Combination; and (iii) at least a majority of the members of the Board of Directors of the entity resulting from such Business Combination or any direct or indirect parent corporation thereof were members of the Incumbent Board at the time of the execution of the initial agreement or action of the Board providing for such Business Combination; or

(4) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company, except pursuant to a Business Combination that complies with subsections (c)(i), (ii), and (iii) above.

(5) A Change in Control shall not be deemed to occur solely because any Person (the "**Subject Person**") acquired Beneficial Ownership of more than the permitted amount of the then outstanding Common Stock as a result of the acquisition of Common Stock by the Company which, by reducing the number of shares of Common stock then outstanding, increases the proportional number of shares Beneficially Owned by the Subject Person, provided that if a Change in Control would occur (but for the operation of this sentence) as a result of the acquisition of Common Stock by the Company, and after such stock acquisition by the Company, the Subject Person becomes the Beneficial Owner of any additional Common Stock which increases the percentage of the then outstanding common Stock Beneficially Owned by the Subject Person, then a Change in Control shall occur.

(6) A Change in Control shall not be deemed to occur unless and until all regulatory approvals required in order to effectuate a Change in Control of the Company have been obtained and the transaction constituting the Change in Control has been consummated.

13. WITHHOLDING.

There shall be deducted from all benefits paid under this Plan the amount of any taxes required to be withheld by any federal, state or local government. The Participants and their beneficiaries, distributes and personal representatives, as applicable, will bear any an all federal, foreign, state, local or other income or other taxes imposed on amounts paid under this Plan.

14. ASSIGNABILITY.

No right to receive payments under this Plan shall be subject to voluntary or involuntary alienation, assignment or transfer, sale, bankruptcy, pledge, attachment, charge lien or encumbrance of any kind.

15. ADMINISTRATION OF THE PLAN.

The Plan shall be administered by the Committee. The Committee shall conclusively interpret the provisions of the Plan, decide all claims and shall make all determinations under the Plan. The Committee shall act by vote or written consent of the majority of its members. The Committee may delegate any or all of its duties and authority hereunder to any person.

16. GOVERNING LAW.

This Plan shall be governed by and construed in accordance with the laws of the State of South Dakota.

17. NO CONTRACT.

Neither the action of the Company in establishing the Plan nor any action taken by it or by the Committee under the provisions hereof or any provisions of the Plan shall be construed as giving any Participant the right to be retained as a Director or Employee of the Company.

18. NO TAX-QUALIFIED OR ERISA PLAN.

It is not intended that this Plan be a tax-qualified plan under the Internal Revenue Code nor is it intended that this Plan be an employee benefit plan subject to ERISA because none of the Participants are covered as Employees of the Company. The Participants' rights under the Plan, if any, are contractual.

19. DEFINITIONS.

For purposes of the Plan,

“Account” shall mean the individual bookkeeping account established to track the Company common stock equivalents allocated the Participant and adjustments thereto.

“Affiliate” shall mean any business organization or legal entity that directly or indirectly, controls, is controlled by or is under common control with the Company. For purposes of this definition, the term “control” (including the terms “controlling”, “controlled by”, and “under common control with”) includes the possession, direct or indirect, of the power to vote 50 percent or more of the voting equity securities, membership interest, or other voting interest, or to direct or cause the direction of the management and policies of such business organization or other legal entity, whether through the ownership of voting equity securities, membership interest, by contract, or otherwise.

“Beneficial Owner” or “Beneficial Ownership” shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Exchange Act.

“Benefit Payment Date” shall mean the date on which benefit payments due hereunder are to be paid. All payments hereunder shall actually commence on or within 60 days after the Benefit Payment Date.

“Board of Directors” or “Board” shall mean the Board of Directors of the Company.

“Committee” shall mean the Compensation Committee of the Board of Directors of the Company.

“Director” shall mean a member of the Board of Directors of the Company.

“Exchange Act” shall mean the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

“Key Employee” shall mean a Participant who is a specified employee, as defined as in Section 409A of the Internal Revenue Code and the regulations and other official guidance issued thereunder, and as determined in accordance with procedures established by the Committee.

“Outside Director” shall mean a Director who is not a full-time employee of the Company.

“Participant” shall mean an Outside Director who is participating in the Plan under Section 2.

“Person” shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act and used in Sections 13(d) and 14(d) thereof, including a “group” as defined in Section 13(d).

“Plan Year” shall mean the 12 consecutive month period beginning each January 1 and ending each December 31.

"Quarter Period" shall mean June 1 through August 31, September 1 through November 30, December 1 through February 28 or 29 and March 1 through May 31.

“Separation from Service” shall mean separation from service (including service as a Director, an employee or an independent contractor) with the Company and all Affiliates, as defined for purposes of Code Section 409A and the regulations thereunder.

Dated this 29th day of October, 2008.

BLACK HILLS CORPORATION

By /s/ David R. Emery

David R. Emery
Chairman, President
and Chief Executive Officer

ATTEST:

/s/ Roxann R. Basham

(CORPORATE SEAL)

Exhibit 10.25

**FIRST AMENDMENT TO THE
SHORT-TERM ANNUAL INCENTIVE PLAN**

1. EFFECTIVE DATE.

This First Amendment to the Short-Term Annual Incentive Plan is made effective the 1st day of January, 1999.

2. DEFERRAL ELECTION.

A Participant may elect to defer receipt of all or a specified part of the Incentive Award payable to the Participant. An amount equal to the portion of the Incentive Award deferred will be credited to the Participant's Account in the Black Hills Nonqualified Deferred Compensation Plan. An election to defer an Incentive Award shall be made pursuant to rules and regulations provided by the Committee for that purpose and shall be effective when filed with such Committee with respect to the Incentive Award or any part of it so elected. The deferral election must be filed prior to the end of the year as to which an Incentive Award is to be determined in January of the subsequent Plan Year; provided, that in the Plan Year in which this amendment becomes effective, a Participant may make an election to defer receipt of the Incentive Award within 30 days after the date this amendment is effective, but not later than the day prior to the day on which the Committee determines the Incentive Award.

In the event the Participant defers his or her stock award under this Plan, the Company shall establish a common stock equivalent memorandum account ("Stock Account") and shall credit the Stock Account with Company common stock equivalents.

Dated the date and year first above written.

Black Hills Corporation

By: /s/ Daniel P. Landguth
Daniel P. Landguth
Chairman, President and CEO

SECOND AMENDMENT TO THE
SHORT-TERM ANNUAL INCENTIVE PLAN

1. EFFECTIVE DATE:

This Second Amendment to the Short-Term Annual Incentive Plan is effective January 1, 2009 and supersedes the “First Amendment to Short-Term Annual Incentive Plan”, dated January 1, 1999, in its entirety.

Except as otherwise provided herein, the Company intends that this Plan will be exempt from Code Section 409A under the “short-term deferral” exemption and that the Plan will comply with the exemption under Code Section 409A and the regulations issued thereunder effective January 1, 2009. During the period from January 1, 2005 though December 31, 2008, the Company intends to operate this Plan in reasonable good faith compliance with the “short-term deferral” exemption under Code Section 409A and the interim guidance issued thereunder.

2. AMENDMENT:

Section 6 is amended to add subsections (c) and (d) to read as follows

(c) Except to the extent that a Participant elects to defer payment of an Incentive Award in accordance with the provisions of subsection (d), payment of each Incentive Award shall be made to the Participant within 2-1/2 months after the end of the Plan Year in which the Participant obtains a legally binding right to the Incentive Award or, if later, in which the Incentive Award is no longer subject to a substantial risk of forfeiture. To the extent that a Participant does not elect to defer payment of an Incentive Award, it is the intent of the Company that this Plan shall be exempt from the application of Section 409A of the Internal Revenue Code under the “short-term deferral” exemption.

For purposes of this subsection (c), the terms “legally binding right” and “substantial risk of forfeiture” shall have the meanings assigned to them under Code Section 409A.

(d) A Participant may elect, in accordance with the terms of the Nonqualified Deferred Compensation Plan, to defer receipt of all or a specified portion of an Incentive Award payable to the Participant, in which case an amount equal to the portion of the Incentive Award that the Participant has elected to defer shall be credited to the Participant’s Account in the Black Hills Nonqualified Deferred Compensation Plan on the date payment of the Incentive Award would have been made in the absence of an election to defer. An election to defer an Incentive Award shall be made in writing pursuant to rules and regulations provided by the Committee for that purpose and shall be effective when filed with such Committee with respect to the Incentive Award or any part so elected. The deferral election must be filed by June 30 of the Plan Year prior to the Plan Year in which the Award will be determined or, if earlier, by the day before the date on which the Incentive Award has become readily ascertainable (as defined for purposes of Section 409A of the Internal Revenue Code). In no event shall an election to defer be effective unless the Participant is an employee at all times from the first day of the Plan Year (or, if later, the date the performance measures for the Plan Year have been established) until the date the election is made.

In the event the Participant elects to defer his or her stock award under this Plan, the Company shall establish a common stock equivalent memorandum account ("Stock Account") and shall credit the Stock Account with Company common stock equivalents.

With respect to any amounts that the Participant elects to defer hereunder, it is the intent of the Company that (1) the Plan will comply with the provisions of Section 409A of the Internal Revenue Code and the regulations thereunder, effective January 1, 2009 and (2) during the period beginning January 1, 2005 and ending December 31, 2008, the Plan will be operated in reasonable good faith compliance with the provisions of Section 409A of the Internal Revenue Code and the interim guidance thereunder with respect to any amounts that the Participant elects to defer hereunder.

Except for the Amendment above, the Plan shall remain in full force and effect.

Black Hills Corporation

By: /s/ David R. Emery
David R. Emery
Chairman, President and CEO

EXHIBIT 12

BLACK HILLS CORPORATION
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND
EARNINGS TO FIXED CHARGES AND PREFERRED STOCK DIVIDENDS
(Dollars in thousands)

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Earnings as defined in Regulation S-K –					
Income (loss) from continuing operations	$ (52,167)	$ 75,281	$ 55,262	$ 49,795	$ 44,422
Minority interest	130	377	510	277	186
Income tax expense (benefit)	(29,395)	32,427	23,103	26,633	19,713
(Income) loss from equity investee	(4,366)	1,231	(1,653)	(14,325)	386
Income (loss) from continuing operations before minority interest, earnings from equity investees, and income taxes	(85,798)	109,316	77,222	62,380	64,707
Fixed charges	59,392	34,520	35,018	28,122	25,210
Amortization of capitalized interest	48	93	63	—	—
Distributed income of equity investees	1,781	3,724	4,304	12,956	3,762
Interest capitalized	(1,318)	(2,323)	(1,571)	—	—
Preference security dividend requirements of consolidated subsidiaries	—	—	—	(241)	(472)
Earnings as defined	$ (25,895)	$ 145,330	$ 115,036	$ 103,217	$ 93,207
Fixed Charges as defined in Regulation S-K –					
Interest expense	$ 54,123	$ 25,181	$ 29,946	$ 26,607	$ 24,021
AFUDC interest	2,811	6,415	2,972	694	165
Interest capitalized	1,318	2,323	1,571	—	—
Estimate of interest within rental expense	1,140	601	529	580	552
Fixed Charges as defined	59,392	34,520	35,018	27,881	24,738
Preference security dividend requirements of consolidated subsidiaries	—	—	—	241	472
Fixed Charges and Preference Security Dividend as defined	$ 59,392	$ 34,520	$ 35,018	$ 28,122	$ 25,210
Ratio of Earnings to Fixed Charges [(a)]	(0.44)	4.21	3.29	3.70	3.77
Ratio of Earnings to Fixed Charges and Preference Security Dividend [(a)]	(0.44)	4.21	3.29	3.67	3.70

(a) The earnings as defined in 2008 would need to increase $85.3 million for the 2008 ratios to be 1.0.

Exhibit 21

BLACK HILLS CORPORATION

SUBSIDIARIES
December 31, 2008

Black Hills Artesia, LLC, a Delaware limited liability company

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

Black Hills Electric Generation, LLC, a South Dakota limited liability company

Black Hills Energy Resources, Inc., a South Dakota corporation

Black Hills Exploration and Production, Inc., a Wyoming corporation

Black Hills Gas Holdings Corp., a Colorado corporation

Black Hills Gas Resources, Inc., a Colorado corporation

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

Black Hills Independent Power Fund, Inc., a Texas corporation

Black Hills Ivanpah GP, LLC, a Delaware limited liability company

Black Hills Ivanpah, LLC, a Delaware limited liability company

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

Black Hills Non-regulated Holdings, LLC, a South Dakota limited liability company

Black Hills Ocotillo, LLC, a Delaware limited liability company

Black Hills Ontario, LLC, a Delaware limited liability company

Black Hills Pepperell Power Associates, LLC, a Delaware limited liability company

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

Black Hills Power, Inc., a South Dakota corporation

Black Hills Service Company, LLC, a South Dakota limited liability company

Black Hills Utility Holdings, Inc., a South Dakota corporation

Black Hills Waterville Station, LLC, a South Dakota limited liability company

Black Hills Wyoming, Inc., a Wyoming corporation

Black Hills/Colorado Electric Utility Company, LP, a Delaware limited partnership

Black Hills/Colorado Gas Utility Company, LP, a Delaware limited partnership

Black Hills/Colorado Utility Company II, LLC, a Colorado limited liability company

Black Hills/Colorado Utility Company, LLC, a Colorado limited liability company

Black Hills/Iowa Gas Utility Company, LLC, a Delaware limited liability company

Black Hills/Kansas Gas Utility Company, LLC, a Kansas limited liability company

Black Hills/Nebraska Gas Utility Company, LLC, a Delaware limited liability company

Bloomfield Glenns Ferry, Inc., a Virginia corporation

Bloomfield Idaho Management, Inc., a Delaware corporation

Bloomfield Rupert, Inc., a Virginia corporation

Buick Power, LLC, a Delaware limited liability company

Cheyenne Light, Fuel and Power Company, a Wyoming corporation

Daksoft, Inc., a South Dakota corporation

EIF Investors, Inc., a Delaware corporation

Enserco Energy Inc., a South Dakota corporation

Enserco Midstream, LLC, a South Dakota limited liability company

Glenns Ferry Cogeneration Partners, Ltd., a Colorado limited partnership

Glenns Ferry Management, Inc., a Delaware corporation

Natural/Peoples Limited Liability Company, a Wyoming limited liability company

Rupert Cogeneration Partners, Ltd., a Colorado limited partnership

Rupert Management, Inc., a Delaware corporation

Varifuel, LLC, a South Dakota limited liability company

West Cascade Energy, LLC, a Delaware limited liability company

Wyodak Resources Development Corp., a Delaware corporation

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-150669, 333-141727, and 333-150664 on Form S-3 and Registration Statement Nos. 333-61969, 333-17451, 333-82787, 333-63264, 333-125697, and 333-135431 on Form S-8 of our report dated March 2, 2009, relating to the consolidated financial statements and financial statement schedule of Black Hills Corporation and subsidiaries (the "Company") (which report on the consolidated financial statements expresses an unqualified opinion and includes explanatory paragraph regarding the adoption of new accounting standards), and our report dated March 2, 2009 regarding the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2008.

DELOITTE & TOUCHE LLP

Minneapolis, MN
March 2, 2009

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEER AND GEOLOGIST

As petroleum engineers, we hereby consent to the inclusion of the information included in this Form 10-K with respect to the oil and gas reserves of Black Hills Exploration and Production, Inc., the future net revenues from such reserves, and the present value thereof, which information has been included in this Form 10-K in reliance upon the report of this firm and upon the authority of this firm as experts in petroleum engineering. We hereby further consent to all references to our firm included in this Form 10-K and to the incorporation by reference in the Registration Statements on Form S-8 Nos. 333-61969, 333-17451, 333-82787, 333-63264, 333-125697 and 333-135431 and the Registration Statements on Form S-3, Nos. 333-150664, 333-150669 and 333-141727.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

/S/ J. ZANE MEEKINS

J. Zane Meekins
Senior Vice President

Fort Worth, Texas
February 26, 2009

Exhibit 31.1

CERTIFICATION

I, David R. Emery, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2009

/s/ David R. Emery
Chairman, President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Anthony S. Cleberg, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2009

/s/ Anthony S. Cleberg
Executive Vice President and
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 2, 2009

/s/ David R. Emery
David R. Emery
Chairman, President and
Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Anthony S. Cleberg, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 2, 2009

/s/ Anthony S. Cleberg
Anthony S. Cleberg
Executive Vice President and
Chief Financial Officer