BEHIND THE ENERGY

2010 BHC ANNUAL REPORT
PROXY STATEMENT
FORM 10K

CHAIRMAN'S LETTER

2010 Annual Report

Dear Shareholders,

The work we do at Black Hills Corporation often happens far from the spotlight. As a diversified energy company, our job is to support our customers as they go about their daily lives — whether they're heating their homes, switching on lights or delivering energy produced by our non-regulated business units to serve their own customers.

But being in a supporting role doesn't mean we can't or shouldn't tell our own story. Our customers, shareholders, employees and communities deserve to know why we do what we do — as well as the amount of work that goes into delivering our energy — so that they understand the decisions we make as we serve them.

Last year, there were several good examples of the work that goes in to supporting our customers, all while making sure we provide a fair return for our shareholders. Not only did we improve our earnings in 2010, but we also made significant progress on many of our key strategic initiatives. And in January 2011 for the 41st consecutive year, we increased our quarterly dividend for shareholders, an indication of the financial strength of our company and the shareholder value we continue to create.

On April 1, Black Hills Power's new 110-megawatt, coal-fired, mine-mouth power plant, Wygen III, began commercial operation ahead of schedule and under budget. BHP completed a major transmission project last year as well. In July, we started construction on our 180-megawatt natural-gas-fired power facility in Pueblo, Colo., which we are building as a rate-based asset of Black Hills Energy – Colorado Electric. The project is expected to be completed by Jan. 1, 2012, and will cost $250 million to $260 million.

We also entered into a 200-megawatt, 20-year power purchase agreement for Black Hills Energy – Colorado Electric with our independent power generation segment. As a result, we began construction on a 200-megawatt natural-gas-fired power facility, which we expect to complete by Jan. 1, 2012, at a cost of $250 million to $260 million. We were also able to complete Advanced Metering Infrastructure installations for all three of our electric utilities and expanded Automated Meter Reading technology in our gas utility territories.

New rates were implemented last year at five of our utilities, including Black Hills Power in South Dakota and Wyoming, Black Hills Energy – Nebraska Gas, and Black Hills Energy – Colorado Electric, and interim rates went into affect at Black Hills Energy – Iowa Gas. In the first quarter of 2011, the Iowa Utilities Board approved a final $3.4 million general increase and recovery of rate case expenses for Iowa Gas. In total, these new rates resulted in a $47.1 million increase in annual revenues for our company.

As of year-end, essentially all of the significant projects needed to fully integrate the systems and processes of the utility properties acquired in mid-2008 were completed, creating operating efficiencies and a scalable platform to support future growth. These completed projects included the integration of our human resources, financial and customer information systems, which required a substantial investment on our part — both in terms of the number of hours to complete and the employee resources devoted to their successful implementation.

We were also able to complete a number of significant financings during the year, improving our liquidity. This list of financings included completing a $500 million unsecured corporate revolving credit facility as well as a public debt offering of $200 million senior unsecured notes. We closed on a $100 million, one-year term loan providing additional liquidity to manage financing needs related to the construction in Colorado, and we executed a public offering of 4.4 million shares of common stock through a forward sale to be settled in 2011. At our energy marketing business, Enserco, we completed a two-year $250 million committed, stand-alone credit facility with a $100 million accordion feature, replacing a one-year $300 million committed credit facility.

Although market conditions continued to challenge our non-regulated energy marketing and oil and gas businesses, our overall non-regulated energy earnings still improved considerably compared to 2009.

In 2011, we will continue the review of our oil and gas strategy that we announced in May, and we are optimistic about the potential value of our existing oil and gas holdings. We plan to focus on drilling several wells to evaluate the potential of the Mancos Shale formation beneath our existing acreage in the San Juan and Piceance basins of New Mexico and Colorado. We also plan to continue our participation in the Bakken Oil Shale play in the Williston Basin in North Dakota and Montana and intend to participate in other select oil prospects during the year as well.

During the year, we diversified Enserco through the addition of coal, power and environmental product marketing. This reduces our dependence on natural gas storage and transport margins, which have been negatively impacted by weak natural gas markets.

In 2010, we had several organizational changes that will help us leverage the new capabilities of our organization and the skills and knowledge of our employees.

In May, John Vering, a current Director of the company, was named Interim President and General Manager of our oil and gas subsidiary, Black Hills Exploration & Production. John brings 37 years of experience in the oil and gas industry to his role, and he is conducting a review of our oil and gas strategy while continuing to serve on the Board.

Also, Tom Ohlmacher, President and Chief Operating Officer of our non-regulated energy business, retired in March of 2011. We appreciate Tom's many contributions in his 36 years with the company. With his pending retirement, we adjusted our organization structure so that we could further optimize the way we do business.

With this in mind, Linn Evans, President and Chief Operating Officer – Utilities, now has an expanded role that includes our power generation and coal mining operations, which previously reported to Tom. The leaders of our oil and gas and energy marketing subsidiaries now report directly to me.

We say this fairly frequently, but it's worth repeating that our company is well positioned with the most clearly defined long-term growth strategy in our history. We have demonstrated access to the capital markets, which is essential to our future success. Our employees continue to produce amazing results as they serve our customers and successfully execute our business plans. These fundamental strengths, combined with an improving business climate and rising commodity prices, will lead to the strong financial and operational performance our shareholders expect from Black Hills Corporation.

David R. Emery
Chairman, President and Chief Executive Officer

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PROXY STATEMENT

BLACK HILLS CORPORATION

Notice of 2011
Annual Meeting of Shareholders
and Proxy Statement

BLACK HILLS CORPORATION

625 Ninth Street
Rapid City, South Dakota 57701

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS
MAY 25, 2011

April 13, 2011

Dear Shareholder:

You are invited to attend the annual meeting of shareholders of Black Hills Corporation to be held on Wednesday, May 25, 2011 at 9:30 a.m., local time, at the Dahl Arts Center, 713 Seventh Street, Rapid City, South Dakota. The purpose of our annual meeting is to consider and take action on the following:

1. Election of four directors in Class II: David R. Emery, Rebecca B. Roberts, Warren L. Robinson and John B. Vering.
2. Ratification of Deloitte & Touche LLP to serve as our independent registered public accounting firm for the year 2011.
3. An advisory, non-binding resolution to approve our executive compensation.
4. An advisory, non-binding vote on the frequency for which shareholders will have an advisory, non-binding vote on our executive compensation.
5. Any other business that properly comes before the annual meeting.

The enclosed proxy statement discusses the important matters to be considered at this year's meeting. Our common shareholders of record as of April 5, 2011 can vote at the annual meeting.

Your vote is very important. You may vote your shares by telephone, by the Internet or by returning the enclosed proxy. If you own shares of common stock other than the shares shown on the enclosed proxy, you will receive a proxy in a separate envelope for each such holding. Please vote each proxy received. To make sure that your vote is counted if voting by mail, you should allow enough time for the postal service to deliver your proxy before the meeting.

Sincerely,

Roxann R. Basham

ROXANN R. BASHAM
Vice President—Governance and
Corporate Secretary

PROXY STATEMENT

BLACK HILLS CORPORATION

625 Ninth Street
Rapid City, South Dakota 57701

PROXY STATEMENT

A proxy in the accompanying form is solicited by the Board of Directors of Black Hills Corporation, a South Dakota corporation, to be voted at the annual meeting of our shareholders to be held Wednesday, May 25, 2011, and at any adjournment of the annual meeting.

The enclosed form of proxy, when executed and returned, will be voted as set forth therein. Any shareholder signing a proxy has the power to revoke the proxy in writing, addressed to our secretary, or in person at the meeting at any time before the proxy is exercised.

We will bear all costs of the solicitation. In addition to solicitation by mail, our officers and employees may solicit proxies by telephone, fax, or in person. We have retained Georgeson Inc. to assist us in the solicitation of proxies at an anticipated cost of $7,500 plus out-of-pocket expenses. Also, we will, upon request, reimburse brokers or other persons holding stock in their names or in the names of their nominees for reasonable expenses in forwarding proxies and proxy materials to the beneficial owners of stock.

This proxy statement and the accompanying form of proxy are to be first mailed on or about April 13, 2011. Our 2010 annual report to shareholders is being mailed to shareholders with this proxy statement.

VOTING RIGHTS AND PRINCIPAL HOLDERS

Only our shareholders of record at the close of business on April 5, 2011, will be entitled to vote at the meeting. Our outstanding voting stock as of such record date consisted of 39,408,229 shares of our common stock.

Each outstanding share of our common stock is entitled to one vote. Cumulative voting is permitted in the election of our Board of Directors. Each share is entitled to four votes, one each for the election of four directors, and the four votes may be cast for a single person or may be distributed among two, three or four persons.

PROXY STATEMENT

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PROXY STATEMENT

COMMONLY ASKED QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING PROCESS

Who is soliciting my proxy?

The Board of Directors of Black Hills Corporation.

Where and when is the annual meeting?

9:30 a.m., local time, May 25, 2011 at the Dahl Arts Center, 713 Seventh Street, Rapid City, South Dakota.

What am I voting on?

- Election of four directors in Class II: David R. Emery, Rebecca B. Roberts, Warren L. Robinson and John B. Vering.
- Ratification of Deloitte & Touche LLP as our independent registered public accounting firm for 2011.
- An advisory, non-binding resolution to approve our executive compensation.
- An advisory, non-binding vote on the frequency for which shareholders will have an advisory, non-binding vote on our executive compensation.

Who can vote?

Holders of our common stock as of the close of business on the record date, April 5, 2011, can vote at our annual meeting. Each share of our common stock gets one vote. Cumulative voting is permitted in the election of directors. Each share is entitled to four votes, one each for the election of four directors, and the four votes may be cast for a single person or may be distributed among two, three or four persons.

How do I vote?

There are three ways to vote by proxy:

- by calling the toll free telephone number on the enclosed proxy;
- by using the Internet; or
- by returning the enclosed proxy in the envelope provided.

You *may* be able to vote by telephone or the Internet if your shares are held in the name of a bank or broker. If this is the case, you will need to follow their instructions.

If we receive your signed proxy before the annual meeting, we will vote your shares as you direct. You can specify on your proxy whether your shares should be voted for all, some or none of the nominees for directors. You can also specify whether you approve, disapprove or abstain from the other proposals.

If you do not mark any sections, your proxy card will be voted:

- in favor of the election of the directors named in Item 1; and
- in favor of Items 2 and 3 and the option of *One* Year on Item 4.

Who will count the vote?

Representatives of Wells Fargo Bank, N.A. will count the votes and serve as judges of the election.

What constitutes a quorum?

Shareholders representing at least 50 percent of our common stock issued and outstanding as of the record date must be present at the annual meeting, either in person or by proxy, for there to be a quorum. Abstentions and broker non-votes are counted as present for establishing a quorum. A broker non-vote occurs when a broker or other nominee holding shares for a beneficial owner does not vote on a particular proposal because the broker or nominee does not have discretionary voting power and has not received instructions from the beneficial owner.

What vote is needed for these proposals to be adopted?

Item 1—Election of Directors. The affirmative vote of a plurality of the votes cast at the meeting is required for the election of directors. This means that the nominees with the largest number of votes "For" will be elected as directors, up to the maximum number of directors to be chosen at the election. A properly executed proxy marked "Withhold authority" with respect to the election of one or more directors will not be voted with respect to the director or directors indicated, although it will be counted for purposes of determining whether there is a quorum.

Item 2—Ratification of Auditors. The appointment of Deloitte & Touche LLP as our independent registered public accounting firm for the year 2011 will be ratified if the votes cast "For" exceed the votes cast "Against." Abstentions will have no effect on such vote.

Item 3—Advisory Vote on Executive Compensation. The advisory vote on executive compensation ("say on pay") is non-binding. However, our Board of Directors will consider shareholders to have approved our executive compensation if the number of votes cast "For" the proposal exceeds the number of votes cast "Against" the proposal. Abstentions and broker non-votes will have no effect on such vote.

Item 4—Advisory Vote on the Frequency of the Advisory Vote on Executive Compensation. The advisory vote on the frequency of the advisory vote on executive compensation ("say when on pay") is non-binding. However, our Board of Directors will consider the frequency receiving the greatest number of votes (every one, two or three years) as the frequency recommended by shareholders. Abstentions and broker non-votes will have no effect on such vote.

How will my shares be voted if they are held in a broker's name?

If you hold your shares through an account with a bank or broker, the bank or broker may vote your shares on some matters even if you do not provide voting instructions. Brokerage firms have the authority under the New York Stock Exchange rules to vote shares on certain matters (such as the ratification of auditors) when their customers do not provide voting instructions. However, on other matters (such as the election of directors and matters related to executive compensation, including "say on pay" and "say when on pay"), when the brokerage firm has not received voting instructions from its customers, the brokerage firm cannot vote the shares on that matter and a "broker non-vote" occurs. **This means that brokers may not vote your shares on the election of directors and the "say on pay" and "say when on pay" advisory votes if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.**

What happens if I do not give my broker instructions?

Absent your instructions, the broker will not be able to vote your shares for the election of directors and the "say on pay" and "say when on pay" advisory votes. Therefore, we urge you to instruct your broker in writing to vote shares held in street name.

Is cumulative voting permitted for the election of directors?

In the election of directors, you may elect to cumulate your vote. Cumulative voting will allow you to allocate among the director nominees, as you see fit, the total number of votes equal to the number of director positions to be filled multiplied by the number of shares you hold. For example, if you own 100 shares of stock, and there are four directors to be elected at the annual meeting, you could allocate 400 "For" votes (four times 100) among as few or as many of the four nominees to be voted on at the annual meeting as you choose.

If you choose to cumulate your votes, you will need to submit a proxy card or a ballot and make an explicit statement of your intent to cumulate your votes, either by indicating in writing on the proxy card or by indicating in writing on your ballot when voting at the annual meeting. If you hold shares beneficially in street name and wish to cumulate votes, you should contact your broker, trustee or nominee.

What should I do now?

You should vote your shares by telephone, by the Internet or by returning your signed and dated proxy card in the enclosed envelope as soon as possible so that your shares will be represented at the annual meeting.

Who conducts the proxy solicitation and how much will it cost?

We are asking for your proxy for the annual meeting and will pay all the costs of asking for shareholder proxies. We have hired Georgeson Inc. to help us send out the proxy materials and ask for proxies. Georgeson Inc.'s fee for these services is anticipated to be $7,500, plus out-of-pocket expenses. We can ask for proxies through the mail or by telephone, fax, or in person. We can use our directors, officers and employees to ask for proxies. These people do not receive additional compensation for these services. We will reimburse brokerage houses and other custodians, nominees and fiduciaries for their reasonable out-of-pocket expenses for forwarding solicitation material to the beneficial owners of our common stock.

Can I revoke my proxy?

Yes. You can change your vote in one of four ways at any time before your proxy is used. First, you can enter a new vote by telephone or Internet. Second, you can revoke your proxy by written notice. Third, you can send a later dated proxy changing your vote. Fourth, you can attend the meeting and vote in person.

Who should I call with questions?

If you have questions about the annual meeting, you should call Roxann R. Basham, Vice President—Governance and Corporate Secretary, at (605) 721-1700.

When are the shareholder proposals for the annual meeting held in 2012 due?

In order to be considered for inclusion in our proxy materials, you must submit proposals for next year's annual meeting in writing to our Corporate Secretary at our executive offices at 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to December 15, 2011.

A shareholder who intends to submit a proposal for consideration, but not for inclusion in our proxy materials, must provide written notice to our Corporate Secretary in accordance with Article I, Section 9 of our Bylaws. In general, our Bylaws provide that the written notice must be delivered not less than 90 days nor more than 120 days prior to the first anniversary date of the immediately preceding annual meeting of shareholders. Our 2011 annual meeting is scheduled for

May 25, 2011. Ninety days prior to the first anniversary of this date will be February 25, 2012, and 120 days prior to the first anniversary of this date will be January 26, 2012.

Proposal 1

ELECTION OF DIRECTORS

In accordance with our Bylaws and Article VI of our Articles of Incorporation, members of our Board of Directors are elected to three classes of staggered terms consisting of three years each. At this annual meeting of our shareholders, four directors will be elected to Class II of the Board of Directors to hold office for a term of three years until our annual meeting of shareholders in 2014, and until their respective successors shall be duly elected and qualified in accordance with the Company's Bylaws.

Three nominees for directors are presently members of our Board of Directors, and one is not. Ms. Roberts is standing for election for the first time in connection with this proxy statement and was identified by a third party search firm. The proxy attorneys will vote your stock for the election of the four nominees for directors, unless otherwise instructed. If, at the time of the meeting, any of such nominees shall be unable to serve in the capacity for which they are nominated or for good cause will not serve, an event which the Board of Directors does not anticipate, it is the intention of the persons designated as proxy attorneys to vote, at their discretion, for such nominees as the Governance Committee may recommend and the Board of Directors may propose to replace those who are unable to serve. The affirmative vote of a plurality of the votes cast at the meeting is required for the election of the nominees to the Board of Directors.

At the close of the 2011 Annual Meeting, Kay S. Jorgensen will complete her service as a member of the Black Hills Corporation Board of Directors. Following her initial election in 1992, Ms. Jorgensen provided leadership and counsel to the Board and management, throughout an extended period of growth and transformation for the Company. She served as the Board's Presiding Director from May 2006 to May 2010. The Board of Directors extends its gratitude to Ms. Jorgensen for her distinguished service and contribution to the success of Black Hills Corporation.

The following information, including principal occupation or employment for the past five or more years and a summary of each individual's experience, qualifications, attributes or skills that have led to the conclusion that each individual should serve as a director in light of our current business and structure, is furnished with respect to each nominee and each of the continuing members of the Board of Directors.

The Board of Directors recommends a vote *FOR* the election of the following nominees:

Class II—Nominees for Election Until 2014 Annual Meeting

David R. Emery, 48, has been a director of the Company since 2004.

Chairman, President and Chief Executive Officer of Black Hills Corporation, since 2005. Formerly held various positions with Black Hills Corporation, including President and Chief Executive Officer, President and Chief Operating Officer—Retail Business Segment and Vice President—Fuel Resources. Mr. Emery has 21 years of experience with Black Hills Corporation. Prior to joining the Company, he served as a petroleum engineer for a large independent oil and gas company.

Mr. Emery is the only employee of the Company currently on our Board. With over 20 years of experience at our Company, he has a deep knowledge and understanding of each of our business units and related industries. An enrolled member of the Cheyenne River Sioux Tribe, supports our Company's interest in promoting diverse perspectives. He has demonstrated leadership abilities serving as our Chairman, President and Chief Executive Officer since 2005. His strategic capabilities, knowledge and industry expertise provide critical leadership to the Board.

Rebecca B. Roberts, 58, is standing for election as a director for the first time.

President of Chevron Pipe Line Company, a pipeline company transporting crude oil, refined petroleum products, liquefied petroleum gas, natural gas and chemicals within the United States, from 2006 to February 2011. Ms. Roberts will retire from Chevron effective May 1, 2011. President of Chevron Global Power Generation from 2003 to 2006. Previously a Director of Dynegy, Inc. serving as Chevron's representative from March 2006 to April 2007.

Ms. Roberts has 37 years of experience in the energy industry. Her industry experience includes managing pipelines in North America and global pipeline projects; managing a portfolio of power plants in the United States, Asia and the Middle East; and work as a Vice President, chemist, scientist and trader in the oil and gas sectors. Her diversified energy industry experience and prior service on a public company provide an in-depth business and strategic acumen and diversity that strengthens our Board's collective qualifications, skills and experiences.

Warren L. Robinson, 61, has been a director of the Company since 2007.

Retired. Former Executive Vice President, Treasurer and Chief Financial Officer of MDU Resources Group, Inc., a diversified energy and resources company, from 1992 to January 2006. Director of TMI Systems Design Corporation, a private manufacturer of laminate casework, since 2006.

Mr. Robinson has 29 years of experience in the utility industry, 18 of those years with MDU Resources Group. His industry experience at MDU included regulated utility finance and operations, and oil and gas exploration and production, two critical business segments for our Company. Mr. Robinson's service as a chief executive for accounting and finance activities relating to our industries provides the necessary financial reporting expertise to serve as Chairman of our Audit Committee. His experience as an executive financial leader at a publicly traded energy company provides our Board with current knowledge and understanding of the regulated business model, and unique challenges of the geographic and regulatory environment in which we operate.

John B. Vering, 61, has been a director of the Company since 2005.

Interim President and General Manager of Black Hills Exploration and Production, Inc., our oil and gas subsidiary, since May 2010. Managing Director of Lone Mountain Investments, Inc., oil and gas investments, since 2002. Partner in Vering Feed Yards LLC, a privately owned agricultural company, since March 2010. Previously held several executive positions in the oil and gas industry. Director of Broad Oak Energy, Inc., a privately held oil and gas exploration and production company, since 2006.

Mr. Vering has over 30 years of experience, including executive leadership, in the oil and gas industry. He served for 23 years with Union Pacific Resources Company in several positions, including Vice President of Canadian Operations. He has direct operating experience in oil and gas transportation, marketing, and exploration and production, important business segments for our Company. His knowledge and understanding of the trans-national oil and gas business, and his executive leadership experience strengthens our Board's collective qualifications, skills and experiences. He is currently serving as Interim President and General Manager of our oil and gas subsidiary, pursuant to a consulting agreement, leading a strategic review of our oil and gas assets.

Class III—Directors with Terms Expiring at 2012 Annual Meeting

David C. Ebertz, 65, has been a director of the Company since 1998.

President, Dave Ebertz Risk Management Consulting, a firm specializing in insurance and risk management services for schools and public entities, since 2000. Previous experience in the insurance industry.

Mr. Ebertz resides in the Gillette, Wyoming area, the location of a substantial aggregation of our power generation assets and our coal mine. His service on various local and community boards provides insight into the political, business and regulatory concerns of Wyoming and the Northern Powder River Basin in particular. Mr. Ebertz' experience in insurance and risk management strengthens our Board's collective qualifications, skills and experiences relating to oversight of enterprise risk.

John R. Howard, 70, has been a director of the Company since 1977.

Retired. Former President, Industrial Products, Inc., an industrial parts distributor, providing equipment and supplies to the mining and manufacturing industries, from 1992 to 2003 and Special Projects Manager for Linweld, Inc. in Lincoln, Nebraska.

Mr. Howard is our longest serving board member, and currently is serving his last term as a director pursuant to the mandatory retirement age established in our Bylaws. His extensive experience with our Company included oversight of different management teams throughout a period of substantial growth and change in our industries. Mr. Howard's knowledge of our Company and industries strengthens our Board's collective qualifications, skills and experiences, particularly relating to corporate governance and strategic planning.

Stephen D. Newlin, 58, has been a director of the Company since 2004.

Chairman, President and Chief Executive Officer of PolyOne Corporation, a global provider of specialized polymer materials, services and solutions, since 2006. Former President, Industrial Sector, Ecolab, Inc., a global leader of services, specialty chemicals and equipment serving industrial and institutional clients, from 2003 to 2006. Served as President and a Director of Nalco Chemical Company, a manufacturer of specialty chemicals, services and systems, from 1998 to 2001 and Chief Operating Officer and Chairman from 2000 to 2001. Director of Valspar Corporation since 2007.

Mr. Newlin has been a director of several other public company and non-profit boards in addition to those identified above. He has industry experience in chemicals, water treatment, power generation, mining, energy, petro-chemical and polymer compounds. Mr. Newlin's experience as an active chairman and chief executive officer of a public company and experience on other public company boards, provides an in-depth business, financial and strategic acumen that strengthens our Board's collective qualifications, skills and experience and enables him to be an effective Governance Committee Chairman.

Class I—Directors with Terms Expiring at 2013 Annual Meeting

Jack W. Eugster, 65, has been a director of the Company since 2004.

Retired. Former Chairman, Chief Executive Officer and President of Musicland Stores, Inc., a retail music and home video company, from 1980 until his retirement in 2001. Currently Director of Donaldson Co., Inc. since 1993, Graco, Inc. since 2004 and Life Time Fitness, Inc. since 2009. Previously Director of Golf Galaxy, Inc. from 2000 to 2007 and Director of Shopko Stores, Inc. from 1991 to 2005, serving as Non-Executive Chairman from 2001 to 2005.

Mr. Eugster has been a director of several other public company and non-profit boards in addition to those identified above. He has experience as chairman and chief executive officer of a high-growth public company, and other extensive experience on public company boards, including service on the board of a regulated utility. His past experience lends special expertise relating to acquisitions, divestitures and finance. Mr. Eugster provides in-depth business, financial and strategic acumen that strengthens our Board's collective qualifications, skills and experience and enables him to be an effective Compensation Committee Chairman.

Gary L. Pechota, 61, has been a director of the Company since 2007.

President and Chief Executive Officer of DT-TRAK Consulting, Inc., a medical billing services company, since 2007. Retired from 2005 to 2007. Former Chief of Staff of the National Indian Gaming Commission from 2003 to 2005. Previously held executive positions in the cement industry, including serving as the chief executive officer of a publicly-traded company, and positions in finance and accounting. Currently Director of Insteel Industries, Inc. since 1998 and Texas Industries, Inc. since 2009.

Mr. Pechota's background in finance and accounting provides the necessary expertise to serve on our Audit Committee. An enrolled member of the Rosebud Sioux Tribe, supports our Company's interest in promoting diverse perspectives, as well as expertise relating to our business interests on tribal lands. In addition, his experience as an executive leader at several companies, his public company board experience, and his knowledge of mining and extracting minerals and the associated environmental issues, strengthens our Board's collective qualifications, skills and experiences.

Thomas J. Zeller, 63, has been a director of the Company since 1997.

Chief Executive Officer, RESPEC, a technical consulting and services firm with expertise in engineering, information technologies, and water and natural resources specializing in emerging environmental protection protocols, since January 2011 and served as President from 1995 to January 2011.

Mr. Zeller is currently Presiding Director of our Board of Directors and is a Past Chairman of our Audit Committee. His industry experience at RESPEC relates to many of our Company's activities concerning technology, engineering and environmental matters. This expertise, in addition to his experience as an executive leader, provides valuable knowledge to our Board and strengthens its collective qualifications, skills and experiences relating to technical aspects of our Company operations and contract relationships.

CORPORATE GOVERNANCE

Corporate Governance Guidelines. Our Board of Directors has adopted corporate governance guidelines titled "Corporate Governance Guidelines of the Board of Directors" which set the tone for operation of our Board and assist the Board in fulfilling its obligations to shareholders and other constituencies. The guidelines lay the foundation for the Board's responsibilities, operations, leadership, organization and committee matters. The Governance Committee reviews the guidelines annually, and the guidelines may be amended at any time, upon recommendation by the Governance Committee and approval of the Board.

Board Independence. In accordance with New York Stock Exchange rules, the Board of Directors through its Governance Committee affirmatively determines the independence of each director and director nominee in accordance with guidelines it has adopted, which include all elements of independence set forth in the New York Stock Exchange listing standards. These guidelines are contained in our Policy for Director Independence, which can be found in the "Governance" section of our website (www.blackhillscorp.com/corpgov.htm). Based on these standards, the Governance Committee determined that each of the following non-employee directors and director nominee is independent and has no relationship with the Company, except as a director and shareholder of the Company:

David C. Ebertz	Jack W. Eugster	John R. Howard
Kay S. Jorgensen	Stephen D. Newlin	Gary L. Pechota
Rebecca B. Roberts	Warren L. Robinson	Thomas J. Zeller

In addition, based on such standards, the Governance Committee determined that Messrs. Emery and Vering are not independent. Mr. Emery is not independent because he is our Chairman, President and Chief Executive Officer (the "CEO"). Mr. Vering is not independent because of his role as Interim President and General Manager of our oil and gas company and our consulting contract with Lone Mountain Investments Inc., of which Mr. Vering is Managing Director.

Board Leadership Structure. As noted above, our Board is currently comprised of ten directors, eight of which are independent. Mr. Emery has served as our Chairman of the Board and CEO since 2005, and has been a member of our Board since 2004. Mr. Emery provides strategic, operational, and technical expertise and context for the matters considered by our Board. After considering alternative board leadership structures, our Board chose to retain the ability to balance an independent Board structure with the flexibility to appoint as Chairman a CEO-Director with knowledge of and experience in the operations of our Company. At this time, our Board believes that having a single person serve as Chairman and CEO provides unified and responsible leadership for our Company.

Our Board has been, and continues to value a high degree of Board independence. As a result, our corporate governance structure and practices promote a strong, independent Board, and include several independent oversight mechanisms, including only independent directors serving on our Audit, Compensation and Governance Committees and appointing a Presiding Director. Our Board believes these practices ensure that experienced and independent directors will continue to effectively oversee management and critical issues related to financial and operating plans, long-range strategic issues, enterprise risk and corporate integrity. All of our Board Committees may seek legal, financial or other expert advice from a source independent of management.

Our Board annually appoints a Presiding Director. Thomas J. Zeller is our current Presiding Director and has served in this role since May 2010. The responsibilities of Presiding Director, as provided in the Board's Governance Guidelines, are to chair executive sessions of the independent directors and communicate the Board's annual evaluation of the CEO. The Presiding Director, together with the independent directors, establishes the agenda for executive sessions, which are held at each regular Board meeting. The Presiding Director serves as a liaison between the independent members of the Board and the CEO, and discusses, to the extent appropriate, matters raised by the independent directors in executive session. The Presiding Director also presides over regular meetings of the Board in the absence of the Chairman. This leadership structure provides consistent and effective oversight of our management and our Company.

Risk Oversight. Our Board oversees an enterprise approach to risk management that supports the operational and strategic objectives of the Company. The Corporate Governance Guidelines of our Board of Directors provide that the Board will review major risks facing our Company and the options for risk mitigation presented by management. Our Board delegates oversight of certain risk considerations to its committees within each of their respective areas of responsibility; however, the full Board monitors risk relating to strategic planning and execution, as well as executive succession. Financial risk oversight falls within the purview of our Audit Committee. Our Compensation Committee oversees compensation and benefit plan risks. Each committee reports to the full Board.

Our Board reviews any material changes in the Company's key enterprise risk management issues with management at each quarterly Board meeting in conjunction with the presentation of quarterly financial results. In so doing, our Board seeks to ensure appropriate risk mitigation strategies are implemented by management on an ongoing basis. Operational and strategic plan presentations by management to our Board include consideration of the challenges and risks to our business. Our Board and management actively engage in discussions of these topics and utilize outside consultants as needed. Our Board oversees development of the Company's strategic plan risks as part of its annual strategic planning meeting. In addition, our Board receives environmental, safety, legal and compliance reports at least annually.

Our Audit Committee oversees management's strategy and performance relative to the significant financial risks of the Company. In consultation with management, the independent auditors and the internal auditors, the Audit Committee discusses the Company's risk assessment, risk management and credit policies, and reviews significant financial risk exposures along with steps management has taken to monitor, mitigate and report such exposures. At least twice a year, our Chief Risk Officer provides a Risk and Credit Report to the Audit Committee. The Company adopted Risk Policies and Procedures for our energy marketing operations that address governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct and other concerns. The Company also adopted a Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Committee. The Audit Committee reviews these policies as the Internal Audit Department regularly reports audit results concerning compliance with these policies to them.

Our Compensation Committee adopted an executive compensation philosophy that provides the foundation for our executive compensation program. The executive compensation philosophy states that the executive pay program should be market-based and maintain an appropriate and competitive balance between fixed and variable pay elements, short- and long-term compensation and cash and stock-based compensation. The Committee establishes company-specific performance goals and potential incentive payouts for our executive officers to motivate and reward performance, consistent with the long-term success of the Company. The target compensation for our senior officers is heavily weighted in favor of long-term incentives, aligning performance incentives with long-term results for our shareholders. Our Compensation Committee also sets minimum performance thresholds and maximum payouts in the incentive programs, and maintains the discretion to reduce awards if excessive risk is taken. Stock ownership guidelines established for all of our officers require our executives to hold 100 percent of all shares awarded to them until the ownership guidelines are achieved. Our Compensation Committee also instituted "claw-back" provisions in our incentive plans, which may require an executive to return incentives received, if the Committee determines, in its discretion, that the executive engaged in specified misconduct or wrongdoing.

Our management is responsible for day-to-day risk management. Reporting to the senior management team, our Treasury, Risk Management, Compliance and Internal Audit groups provide the primary monitoring and testing services in accordance with company-wide policies and procedures, and oversee the day-to-day risk management strategy for our ongoing businesses. Their oversight includes identifying, evaluating, and addressing potential risks that may exist at the enterprise, strategic, financial, operational, and compliance and reporting levels.

We believe this division of risk management responsibilities described above is an effective approach for addressing the risks facing our Company.

Director Nominees. The Governance Committee utilizes a variety of methods for identifying and evaluating nominees for director. The Committee regularly assesses the appropriate size of the Board, and whether any vacancies on the Board are expected due to retirement or otherwise. In the event vacancies are anticipated, or otherwise arise, the Committee considers various potential candidates for director. Board candidates are considered based upon various criteria, including diverse business, administrative and professional skills or experiences; an understanding of relevant industries, technologies and markets; financial literacy; independence status; the ability and willingness to contribute time and special competence to Board activities; personal integrity and independent judgment; and a commitment to enhancing shareholder value. The Committee considers these and other factors as it deems appropriate, given the needs of the Board and the Company. Our goal is a balanced and diverse Board, with members whose skills, background and experience are complementary and, together, cover the spectrum of areas that impact our business. The Committee considers candidates for Board membership suggested by a variety of sources, including current or past Board members, the use of third-party executive search firms, members of management and shareholders. There are no differences in the manner by which the Committee evaluates director candidates recommended by shareholders from those recommended by other sources.

Shareholders who intend to nominate persons for election to the Board of Directors must provide timely written notice of the nomination in accordance with Article I, Section 9 of our Bylaws. Generally, our Corporate Secretary must receive the written notice at our executive offices at P.O. Box 1400, 625 Ninth Street, Rapid City, South Dakota, 57709, not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders. The notice must set forth at a minimum the information set forth in Article I, Section 9 of our Bylaws, including the shareholder's identity and status, contingent ownership interests, description of any agreement made with others acting in concert with respect to the nomination, specific information about the nominee and supply certain representations by the nominee to the Company.

Communications with the Board. Shareholders and others interested in communicating directly with the Presiding Director, with the independent directors as a group, or the Board of Directors may do so in writing to the Presiding Director, Black Hills Corporation, P.O. Box 1400, 625 Ninth Street, Rapid City, South Dakota, 57709.

Corporate Governance Documents. The charters of the Audit, Compensation and Governance committees, as well as the Board's Corporate Governance Guidelines, Policy for Director Independence, Code of Business Conduct and the Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, Corporate Controller, and certain other persons performing similar functions can be found in the "Governance" section of our website (www.blackhillscorp.com/corpgov.htm). We intend to disclose any amendments to, or waivers of the Code of Ethics on our website. Please note that none of the information contained on our website is incorporated by reference in this proxy statement.

Certain Relationships and Related Party Transactions. We recognize related party transactions can present potential or actual conflicts of interest and create the appearance that decisions are based on considerations other than the best interests of the Company and our shareholders. Accordingly, as a general matter, it is our preference to avoid related party transactions. Nevertheless, we recognize that there are situations where related party transactions may be in, or may not be inconsistent with, the best interests of the Company and our shareholders, including but not limited to situations where we may obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to related parties on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. Therefore, our Board of Directors has adopted a policy for the review of related party transactions. This policy requires directors and officers to promptly report to our Vice President—Governance all proposed or existing transactions in which the Company and they, or persons related to them, are parties or participants. Our Vice President—Governance presents to our Governance Committee those transactions that may require disclosure pursuant to Item 404 of Regulation S-K (typically, those transactions that exceed $120,000). Our Governance Committee reviews the material facts presented and either approves or disapproves entry into the transaction. In reviewing the transaction, the Governance Committee considers the following factors, among other factors it deems appropriate: (i) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances; (ii) the extent of the related party's interest in the transaction; and (iii) the impact on a director's independence in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance. Based solely upon a review of our records and copies of reports on Form 3, 4 and 5 furnished to us, we believe that during and with respect to 2010, all persons subject to the reporting requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, filed the required reports on a timely basis, except for two Form 4s reporting two transactions for Mr. Ohlmacher relating to market sales pursuant to a 10b5-1 Plan.

MEETINGS AND COMMITTEES OF THE BOARD

The Board of Directors

Our directors review and approve our strategic plan and oversee management of the Company. Our Board of Directors held six meetings during 2010. Directors' attendance at all Board and Committee meetings averaged 97 percent. During 2010, every director attended at least 75 percent of the combined total of Board meetings and Committee meetings on which the director served. Each regularly scheduled meeting of the Board includes an executive session of only independent directors. We encourage our directors to attend the annual shareholders' meeting. All 10 directors were in attendance at the 2010 annual meeting of shareholders.

Committees of the Board

Our Board has three standing committees to facilitate and assist the Board in the execution of its responsibilities. The committees are currently the Audit Committee, the Compensation Committee and the Governance Committee. In accordance with the New York Stock Exchange listing standards and our Corporate Governance Guidelines, the Audit, Compensation and Governance Committees are comprised solely of independent directors. Each committee operates under a charter which is available on our website at www.blackhillscorp.com/corpgov.htm and is also available in print to any shareholder who requests it. In addition, our Board creates special committees from time to time for specific purposes.

Members of the Committees are designated by our directors upon recommendation of the Governance Committee. The table below shows current membership for each of the Board committees.

Audit Committee	Compensation Committee	Governance Committee
John R. Howard	David C. Ebertz	David C. Ebertz
Gary L. Pechota	Jack W. Eugster*	Jack W. Eugster
Warren L. Robinson*	Kay S. Jorgensen	Kay S. Jorgensen
	Stephen D. Newlin	Stephen D. Newlin*
	Thomas J. Zeller	Gary L. Pechota

* Committee Chairperson

Audit Committee. The Audit Committee held seven meetings in 2010. The Audit Committee's responsibilities, discussed in detail in its charter include, among other duties, the responsibility to:

- assist the Board in fulfilling its responsibility for oversight of the quality and integrity of our accounting, auditing and financial reporting practices;
- monitor the integrity of our financial reporting process, systems of internal controls and disclosure controls regarding finance, accounting and legal compliance;
- review areas of potential significant financial risk to the Company;
- review consolidated financial statements and disclosures;
- appoint an independent registered public accounting firm for ratification by our shareholders;
- monitor the independence and performance of our independent registered public accountants and internal auditing department;
- pre-approve all audit and non-audit services provided by our independent registered public accountants;
- review the scope and results of the annual audit including reports and recommendations of our independent registered public accountants;
- review the internal audit plan, results of internal audit work and the Company's process for monitoring compliance with our Code of Conduct; and
- periodically meet with our internal audit group, management, and independent registered public accounting firm.

In accordance with the rules of the NYSE, all of the members of the Audit Committee are financially literate. In addition, the Board determined that Messrs. Howard, Pechota and Robinson each have the requisite attributes of an "audit committee financial expert" as provided in regulations promulgated by the Securities and Exchange Commission, and that such attributes were acquired through relevant education and/or experience.

Compensation Committee. The Compensation Committee held six meetings in 2010. The Compensation Committee's responsibilities, discussed in detail in its charter include, among other duties, the responsibility to:

- discharge the Board of Director's responsibilities related to executive and director compensation philosophy, policies and programs;
- perform functions required of directors in the administration of all federal and state laws and regulations pertaining to executive employment and compensation;
- consider and recommend for approval by the Board all executive compensation programs including executive benefit programs and stock ownership plans; and

- promote an executive compensation program that supports the overall objective of enhancing shareholder value.

The Compensation Committee has authority under its charter to retain and terminate compensation consultants, outside counsel and other advisors as the Committee may deem appropriate in its sole discretion. The Committee has sole authority to approve related fees and retention terms. The Committee may delegate any of its responsibilities to subcommittees as the Committee may deem appropriate in its sole discretion. The Committee engaged Towers Watson, an independent consulting firm, to conduct an annual review of its 2010 total compensation program for executive officers and directors. In addition, Towers Watson was engaged by management to provide certain other services, including an energy marketing compensation review, services related to union negotiations and grievances and an actuarial analysis of insurance claims. Management discussed with the Committee the other work to be performed by Towers Watson. Total aggregate fees for services provided to us in 2010 by Towers Watson were $375,000, comprised of $237,000 for services related to executive and director compensation and $138,000 for other services.

The Committee annually evaluates the CEO's performance in light of established goals and objectives, with input from the other independent directors. Based upon the Committee's evaluation and recommendation, the independent directors of the Board set the CEO's annual compensation, including salary, bonus, incentive and equity compensation.

The CEO annually reviews the performance of each of our senior officers and presents a summary of his evaluations to the Committee. The CEO also provides oversight of management's evaluations of our other officers. Senior officers assess performance of all officers reporting to them. Based upon these performance reviews, market analysis conducted by the compensation consultant and discussions with our Chief Human Resources Officer, the CEO recommends the compensation of the officers to the Committee. The Committee may exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process.

More information describing the Compensation Committee's processes and procedures for considering and determining executive compensation, including the role of our CEO and consultants in determining or recommending the amount or form of executive compensation, is included in the Compensation Discussion and Analysis.

In setting non-employee director compensation, the Compensation Committee recommends the form and amount of compensation to the Board of Directors and the Board of Directors makes the final determination. In considering and recommending the compensation of non-employee directors, the Compensation Committee considers such factors as it deems appropriate, including historical compensation information, level of compensation necessary to attract and retain non-employee directors meeting our desired qualifications and market data. In the review of director compensation for 2010, the Compensation Committee retained Towers Watson to provide market information on non-employee director compensation, including annual board and committee retainers, board and committee meeting fees, committee chairperson fees, number of Board meetings and stock based compensation.

Compensation Committee Interlocks and Insider Participation. The Compensation Committee is comprised entirely of independent directors.

Governance Committee. The Governance Committee held three meetings in 2010. The Governance Committee's responsibilities, discussed in detail in its charter include, among other duties, the responsibility to:

- assess the size of the Board and membership needs and qualifications for Board membership;
- identify and recommend prospective directors to the Board to fill vacancies;

- consider and recommend existing Board members to be renominated at our annual meeting of shareholders;
- establish and review guidelines for corporate governance;
- recommend to the Board committee membership and the chairpersons of the committees;
- nominate an independent director to serve as a Presiding Director;
- review the independence of each director and director nominee;
- administer an annual evaluation of the performance of the Board and facilitate an annual assessment of each committee; and
- ensure that the Board oversees the evaluation and succession planning of management.

DIRECTOR COMPENSATION

Director Fees

In 2010, our non-employee director compensation was as follows:

- an annual cash retainer of $36,000, paid on a monthly basis;
- common stock equivalents equal to $50,000 per year, paid on a quarterly basis;
- dividend equivalents on the common stock equivalents equal to the same dividend rate our shareholders receive; and
- a meeting fee of $1,250 for each board and committee meeting attended, provided such committee meetings are substantive in nature and content.

In addition, our Presiding Director and Committee Chairpersons received the following additional compensation:

- Presiding Director—an annual fee of $15,000;
- Audit Committee Chairperson—an annual fee of $10,000; and
- Compensation and Governance Committee Chairpersons—annual fees of $6,000.

Effective January 1, 2011, our non-employee director compensation was increased to the following:

- an annual cash retainer of $36,000, paid on a monthly basis;
- common stock equivalents equal to $60,000 per year, paid on a quarterly basis;
- dividend equivalents on the common stock equivalents equal to the same dividend rate our shareholders receive; and
- a meeting fee of $1,500 for each board and committee meeting attended, provided such committee meetings are substantive in nature and content.

In addition, our Presiding Director and Committee Chairpersons receive the following additional compensation:

- Presiding Director—an annual fee of $15,000;
- Audit Committee Chairperson—an annual fee of $10,000;
- Compensation Committee Chairperson—an annual fee of $8,000; and
- Governance Committee Chairperson—an annual fee of $6,000.

Director Total Compensation for 2010 and Common Stock Equivalents Outstanding as of December 31, 2010(1)

Name(2)	Fees Earned or Paid in Cash	Stock Awards(3)	All Other Compensation	Total	Number of Common Stock Equivalents Outstanding at December 31, 2010(4)
David C. Ebertz	$59,750	$50,000	—	$109,750	12,053
Jack W. Eugster	$65,750	$50,000	—	$115,750	9,190
John R. Howard	$62,250	$50,000	—	$112,250	18,867
Kay S. Jorgensen	$65,375	$50,000	—	$115,375	14,139
Stephen D. Newlin	$64,500	$50,000	—	$114,500	9,410
Gary L. Pechota	$62,250	$50,000	—	$112,250	6,550
Warren L. Robinson	$73,500	$50,000	—	$123,500	6,726
John B. Vering(5)	$25,000	$50,000	$382,525	$457,525	8,550
Thomas J. Zeller	$66,625	$50,000	—	$116,625	12,465

(1) Our directors did not receive any option awards, non-equity incentive plan compensation, pension benefits or perquisites in 2010.

(2) Mr. Emery, our CEO, is not included in this table as he is an employee of the Company and thus receives no compensation for his services as a director. Mr. Emery's compensation received as an employee is shown in the Summary Compensation Table for our Named Executive Officers.

(3) Each non-employee director received a quarterly award of common stock equivalents with a grant date fair value of $12,500 a quarter or $50,000 a year.

(4) The common stock equivalents are fully vested in that they are not subject to forfeiture; however, the shares are not issued until after the director ends his or her service on the Board. The common stock equivalents are payable in stock or cash or can be deferred further at the election of the director.

(5) Mr. Vering has been serving as Interim President and General Manager of our oil and gas subsidiary since May 2010, leading a strategic review of our oil and gas assets. In exchange for his services, pursuant to a consulting agreement dated May 3, 2010, he receives $42,000 per month and temporary living expenses. He may also receive a project completion bonus to be determined by the Board of Directors, not to exceed $150,000. He does not receive cash Board compensation during the term of the agreement. In 2010, he received $336,000 for his services as Interim President and General Manager and was provided temporary living expenses totaling $46,525. The consulting agreement, unless extended, expires July 31, 2011.

Director Stock Ownership Guidelines

Members of our Board of Directors are required to apply at least 50 percent of his or her annual cash retainer toward the purchase of shares of common stock until the director has accumulated at least 7,500 shares of common stock or common stock equivalents. All of our directors have currently met their stock ownership guidelines.

SECURITY OWNERSHIP OF MANAGEMENT AND PRINCIPAL SHAREHOLDERS

The following tables set forth the beneficial ownership of our common stock as of March 31, 2011 for each director, each executive officer named in the Summary Compensation Table, all of our directors and executive officers as a group, and each person or entity known by us to beneficially own more than five percent of our outstanding shares of common stock. Beneficial ownership includes shares a director or executive officer has the power to vote or transfer, and stock options that are exercisable currently or within 60 days of March 31, 2011.

Except as otherwise indicated by footnote below, we believe that each individual or entity named has sole investment and voting power with respect to the shares of common stock indicated as beneficially owned by that individual or entity.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned(1)	Options Exercisable Within 60 Days	Directors Common Stock Equivalents(2)	Total	Percentage(3)
Directors and Named Executive Officers					
Anthony S. Cleberg(4)	36,002			36,002	*
David C. Ebertz	6,596		12,661	19,257	*
David R. Emery(5)	111,954	30,832		142,786	*
Jack W. Eugster	13,000		9,764	22,764	*
Linden R. Evans	46,217	10,000		56,217	*
Steven J. Helmers	41,045	19,110		60,155	*
John R. Howard	16,864		19,555	36,419	*
Kay S. Jorgensen	7,795		14,771	22,566	*
Stephen D. Newlin	2,634		9,986	12,620	*
Thomas M. Ohlmacher	47,449	2,500		49,949	*
Gary L. Pechota	6,104		7,093	13,197	*
Rebecca B. Roberts	—		—	—	*
Warren L. Robinson(6)	4,593		7,271	11,864	*
John B. Vering(7)	6,763		9,117	15,880	*
Thomas J. Zeller(8)	6,581		13,077	19,658	*
All directors and executive officers as a group (17 persons)	394,525	62,442	103,294	560,261	1.4%

* Represents less than one percent of the common stock outstanding.

(1) Includes restricted stock held by the following executive officers for which they have voting power but not investment power and stock underlying restricted stock units the executive officers have the right to acquire within 60 days as to which they have no current voting or investment power: Mr. Cleberg—13,724 shares; Mr. Emery—27,635 shares; Mr. Evans—15,299 shares; Mr. Helmers—10,380 shares; Mr. Ohlmacher—5,614 shares and 33,326 restricted stock units; and all directors and executive officers as a group—92,411 shares and 33,326 restricted stock units.

(2) Represents common stock allocated to the directors' accounts in the directors' stock based compensation plan, of which there are no voting rights.

(3) Shares of common stock which were not outstanding but could be acquired by a person upon exercise of an option within 60 days of March 31, 2011, are deemed outstanding for the purpose of computing the percentage of outstanding shares beneficially owned by such person. Such shares, however, are not deemed to be outstanding for the purpose of computing the percentage of outstanding shares beneficially owned by any other person.

(4) Includes 140 shares owned by Mr. Cleberg's spouse and 3,185 shares owned by the Fern Wagner Revocable Living Trust of which Mr. Cleberg is the Trustee.

(5) Includes 82,694 shares owned jointly with Mr. Emery's spouse as to which he shares voting and investment authority and 4,500 shares that are pledged as security on a personal bank loan.

(6) Includes 500 shares owned by Mr. Robinson's spouse.

(7) Includes 4,000 shares owned jointly with Mr. Vering's spouse as to which he shares voting and investment authority.

(8) Includes 225 shares owned jointly with Mr. Zeller's spouse as to which he shares voting and investment authority.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percentage
Five Percent Shareholders		
BlackRock, Inc.(1) 40 East 52nd Street New York, NY 10022	4,936,242	12.5%
Dos Mil Doscientos Uno, Ltd.(2) Ronda Universitat, 31 1-1 Barcelona, Spain 08007	2,373,380	6.0%
State Street Corporation(3) One Lincoln Street Boston, MA 02111	3,042,230	7.7%

(1) Information is as of December 31, 2010, and is based on a Schedule 13G filed on January 10, 2011.

(2) Information is as of December 31, 2009, and is based on a Schedule 13G filed on January 27, 2010.

(3) Information is as of December 31, 2010, and is based on a Schedule 13G filed on February 11, 2011.

Proposal 2

RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The firm of Deloitte & Touche LLP, independent registered public accountants, conducted the audit of Black Hills Corporation and its subsidiaries for 2010. Representatives of Deloitte & Touche LLP will be present at our annual meeting and will have the opportunity to make a statement, if they desire to do so, and to respond to appropriate questions.

Our Audit Committee has appointed Deloitte & Touche LLP to perform an audit of our consolidated financial statements and those of our subsidiaries for the year 2011 and to render their reports. The Board of Directors recommends ratification of the Audit Committee's appointment of Deloitte & Touche LLP. If shareholder approval for the appointment of Deloitte & Touche LLP is not obtained, the Audit Committee will reconsider the appointment.

The Board of Directors recommends a vote *FOR* ratification of the appointment of Deloitte & Touche LLP to serve as our independent registered public accountants for the year 2011

FEES PAID TO THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The following table sets forth the aggregate fees for services provided to us for the fiscal years ended December 31, 2010 and 2009 by our independent registered public accounting firm, Deloitte & Touche LLP.

	2010	2009(1)
Audit Fees	$2,688,400	$3,082,500
Audit-Related Fees	148,500	121,700
Tax Fees	787,100	1,092,100
Total Fees	$3,624,000	$4,296,300

(1) The 2009 amounts were adjusted from amounts shown in the 2010 proxy statement to reflect actual costs.

Audit Fees. Fees for professional services rendered for the audits of our consolidated financial statements, review of the interim consolidated financial statements included in quarterly reports, opinions on the effectiveness of our internal control over financial reporting, and services that generally only the independent auditor can reasonably provide, such as comfort letters, statutory audits, consents and assistance with and review of documents filed with the Securities and Exchange Commission.

Audit-Related Fees. Fees for assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements and are not reported under "Audit Fees." These services include internal control reviews; attest services that are not required by statute or regulation; employee benefit plan audits; due diligence, consultations and audits related to mergers and acquisitions; and consultations concerning financial accounting and reporting standards.

Tax Fees. Fees for services related to tax compliance, and tax planning and advice including tax assistance with tax audits. These services include assistance regarding federal, state and Canadian tax compliance and advice, review of tax returns, and federal, state and Canadian tax planning.

The services performed by Deloitte & Touche LLP were pre-approved in accordance with the Audit Committee's pre-approval policy whereby the Audit Committee pre-approves all audit and permissible non-audit services provided by the independent registered public accountants. The Audit Committee will generally pre-approve a list of specific services and categories of services, including audit, audit-related, tax and other services, for the upcoming or current fiscal year, subject to a specified cost level. Any service that is not included in the approved list of services must be separately pre-approved by the Audit Committee.

AUDIT COMMITTEE REPORT

In connection with the financial statements for the fiscal year ended December 31, 2010, the Audit Committee has (1) reviewed and discussed the audited financial statements with management; (2) discussed with Deloitte & Touche LLP, the Company's independent registered public accounting firm (the "Auditors"), the matters required to be discussed by the statement on Auditing Standard No. 61, as amended (AICPA, *Professional Standards,* Vol. 1. AU section 380), as adopted by the Public Accounting Oversight Board in Rule 3200T; and (3) received the written disclosures and letter from the Auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the Auditors' communications with the Audit Committee concerning independence, and has discussed with the Auditors their independence from the Company.

Based upon these reviews and discussions, the Audit Committee recommended to the Board that the Company's audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission.

THE AUDIT COMMITTEE

Warren L. Robinson, Chairperson
John R. Howard
Gary L. Pechota

EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

Introduction

This Compensation Discussion and Analysis describes our overall executive compensation policies and practices and specifically explains the compensation-related actions taken with respect to 2010 compensation for our executive officers included in the Summary Compensation Table (our "Named Executive Officers"). Our Named Executive Officers, based on 2010 positions and compensation levels, are:

- David R. Emery, CEO;
- Anthony S. Cleberg, Chief Financial Officer ("CFO");
- Linden R. Evans, Chief Operating Officer ("COO")-Utilities;
- Thomas M. Ohlmacher, COO-Non-regulated Energy; and
- Steven J. Helmers, Sr. Vice President, General Counsel and Chief Compliance Officer.

Mr. Ohlmacher announced in 2010 that he will retire from the Company on March 31, 2011.

The Compensation Committee of the Board of Directors (the "Committee," for purposes of this Compensation Discussion and Analysis) is composed entirely of independent directors and is responsible for approving and overseeing our executive compensation philosophy, policies and programs.

Executive Summary

Our long-term success depends on our operational excellence, providing reliable products and services to our customers and investing wisely for present and future shareholder return. To consistently achieve these outcomes we must attract, motivate, and retain highly talented professionals. For these reasons, we promote an executive compensation program that supports the overall objective of enhancing shareholder value, based on principles designed to:

- attract, retain and encourage the development of highly qualified and motivated executives;
- provide compensation that is competitive;
- promote the relationship between pay and performance;
- promote overall corporate performance that is linked to the interests of our shareholders; and
- recognize and reward outstanding performance.

2010 Accomplishments

We made substantial progress on our strategic initiatives in 2010. Accomplishments include, among other things:

- Completed the 110 MW Wygen III coal-fired generation facility near Gillette, Wyoming, three months ahead of schedule and at a lower cost than originally anticipated
- Started construction of a 380 MW gas-fired generation facility near Pueblo, Colorado
- Implemented new and interim rates in five utility jurisdictions, increasing annual revenue by $47.1 million

- Essentially completed the unification and integration of systems and processes necessary to fully integrate the utility properties acquired in mid-2008, creating operating efficiencies and a more scalable platform to support future growth

- Improved our liquidity through a number of financing initiatives, including:

  —completed corporate and energy marketing credit facilities for a combined total of $750 million

  —sold a 23 percent interest in Wygen III

  —completed $300 million of debt financings

  —executed a public offering of common stock pursuant to a Forward Sale Agreement, to be settled in 2011 with net proceeds of approximately $127 million before adjustments

- Increased the annual dividend for the 40th consecutive year

- Achieved a total shareholder return of 27 percent

Key Executive Compensation Objectives and 2010 Compensation Decisions

Overall, our goal is to target total direct compensation (the sum of base salary, short-term bonus and long-term incentives) at the median of the appropriate market when our operating results approximate average performance in relation to our peers.

- The total target compensation for our Named Executive Officers in 2010 averaged 8 percent below the median of the market.

Our executive compensation is designed to maintain an appropriate and competitive balance between fixed and variable compensation components, short- and long-term compensation, and cash as well as stock-based compensation. The total target compensation mix for our Named Executive Officers in 2010 averaged:

- 40 percent fixed and 60 percent variable;

- 60 percent base and short-term incentive and 40 percent long-term incentive; and

- 50 percent cash and 50 percent equity.

We believe that the performance basis for determining compensation should differ by each reward component—base salary, short-term incentive and long-term incentives. Incentive measures (short- and long-term) should emphasize objective, quantitative operating measures. The performance measures for our incentive compensation plans are as follows:

- Base Salary—Merit increases for base salary take into account the individual executive's performance and achievement of goals. In 2010:

  —The Committee approved base salary increases for our Named Executive Officers, excluding Mr. Evans, averaging 4 percent. This was the first base salary increase our Named Executive Officers had received in more than two years. Base salaries were not increased in 2009, due to the difficult external economic conditions and uncertainties that existed at the time.

  —Mr. Evans' base salary was increased 31 percent, reflecting the substantial impact of the acquisition of the Aquila utility properties on his job responsibilities. The acquisition more than doubled our utility assets from $830 million to $2.2 billion, tripled the number of utility employees and increased the number of state jurisdictions of our utility properties from three to seven.

- Short-Term Incentive—The short-term incentive is based on earnings per share targets. This performance measure closely aligns the executives' and shareholders' interests, and fosters teamwork and cooperation.

  —The 2010 short-term target incentive opportunity for our Named Executive Officers remained the same as the prior year and ranged from 30 percent to 200 percent of target. The Committee selected a composite earnings per share goal for the 2010 corporate goal that was weighted 80 percent on non-energy marketing earnings per share and 20 percent on energy marketing earnings per share. The Committee chose this weighted methodology because it addresses the volatility of our energy marketing segment's earnings, and the potential for this volatility to disproportionately influence bonus outcomes for participants in the Short-Term Incentive Plan, both positively and negatively, and also because many participants are not directly involved in this business segment.

  On January 26, 2011, the Committee approved a payout of 160 percent of target under the 2010 Short-Term Incentive Plan, comprised of a 160 percent payout from non-energy marketing earnings and no payout from energy marketing earnings.

- Long-Term Incentive—The long-term incentive is delivered 50 percent in restricted stock that vests over a three-year service period and 50 percent in performance shares. Entitlement to the performance shares is based on our total shareholder return over a three-year performance period compared to our peer group. This performance measure was chosen because it mirrors the market return of our shareholders and compares our performance to that of our peer group.

  Performance Share Plan Payment

  —Although our total shareholder return for 2010 was 27 percent, several factors significantly impacted our financial performance for the January 1, 2008 to December 31, 2010 performance period, including a dramatic decrease in natural gas prices from mid-2008 levels and the global economic crisis that commenced in late 2008.

  —Our total shareholder return for the three-year period was negative 20 percent, which ranked at the 15th percentile of our peer group, resulting in no payout for our Named Executive Officers.

  Restricted Stock Grant

  —Consistent with prior years, the Committee awarded 50 percent of the Named Executive Officers' Long-Term Incentive in restricted stock that ratably vests over three years.

We entered into new change in control agreements with our Named Executive Officers in 2010. The new agreements were entered into to reflect the retirement plan changes that were effective January 1, 2010. Excise tax gross-up provisions were also eliminated in the new agreements. The new change in control agreements expire November 15, 2013.

We also have several governance programs in place to align our executive compensation with shareholder interests and to mitigate risks in our plans. These programs include stock ownership guidelines, limited perquisites, and clawback provisions in our short- and long-term incentive award agreements.

Setting Executive Compensation

Based upon our compensation philosophy, the Committee structures our executive compensation to motivate our officers to achieve specified business goals and to reward them for achieving such goals. The key steps the Committee follows in setting executive compensation are to:

- analyze executive compensation market data to ensure market competitiveness;

- review the components of executive compensation, including base salary, short-term incentive, long-term incentive, retirement and other benefits;
- review total compensation mix and structure; and
- review executive officer performance, responsibilities, experience and other factors cited above, to determine individual compensation levels.

Market Compensation Analysis

The market for our senior executive talent is national in scope and is not focused on any one geographic location, area or region of the country. As such, our executive compensation should be competitive with the national market for senior executives. It should also reflect the executive's responsibilities and duties and align with the compensation of executives at companies or business units of comparable size and complexity. The Committee gathers market information for our corporate executives from the utility and energy industry, recognizing the significant impact of our regulated utility operations on overall company strategy and performance.

The Committee selects and retains the services of an independent consulting firm to periodically:

- provide information regarding practices and trends in compensation programs;
- review and evaluate our compensation program as compared to compensation practices of other companies with similar characteristics, including size and type of business;
- review and assist with the establishment of a peer group of companies; and
- provide a compensation analysis of the executive positions.

The Committee used the services of Towers Watson to evaluate 2010 compensation. Towers Watson gathered data from nationally recognized survey providers, as well as specific peer companies through public filings, which included:

- Towers Watson's 2009 Compensation Data Bank (utility/energy services and general industry);
- Towers Watson's 2009 Energy Marketing & Trading Survey; and
- 20 peer companies representing the energy and utility industry.

The 20 peer companies ranged in revenue size from approximately $800 million to nearly $5 billion with the median at $1.675 billion. These are the same companies the Committee chose for our peer group for our Performance Share Program. The survey data were adjusted for our size using either regression analysis or tabular data from companies with annual revenues between $1 billion and $3 billion.

Our peer companies include:

AGL Resources Inc.	IDACORP, Inc.	NV Energy, Inc.
ALLETE Inc.	MDU Resources Group, Inc.	UIL Holdings Corporation
Avista Corp	NorthWestern Corporation	UniSource Energy Corporation
CH Energy Group Inc.	Otter Tail Corporation	Vectren Corporation
Cleco Corporation	PNM Resources, Inc.	Westar Energy, Inc.
DPL Inc.	Portland General Electric Company	WGL Holdings, Inc.
Great Plains Energy Incorporated		

(Note: Puget Energy was originally included in our peer group but was removed because it was acquired by another company during 2009.)

The salary surveys are one of several inputs into the Committee's decisions regarding appropriate compensation levels. Other factors include company performance, individual performance and experience, the level and nature of the executive's responsibilities, and discussions with the CEO related to the other officers.

Components of Executive Compensation

The components of our executive compensation program consist of a base salary, a short-term incentive plan, and a long-term incentive award program. In addition, we provide income for our officers' retirement and other benefits.

An important component of the total compensation is derived from incentive compensation. Incentive compensation is intended to motivate and encourage our executives to drive performance and achieve superior results for our shareholders. The Committee periodically reviews information provided by the compensation consultant to determine the appropriate level and mix of incentive compensation. Actual income in the form of incentive compensation is realized by the executive as a result of achieving Company goals and overall stock performance. The Committee believes that a significant portion of total target compensation should be comprised of incentive compensation. In order to reward long-term growth as well as short-term results, the Committee establishes incentive targets that emphasize long-term compensation at a greater level than short-term compensation.

The Committee annually reviews all components of each executive officer's compensation, including salary, short-term incentive, equity and other long-term incentive compensation values granted, and the current and potential value of the executive officer's total equity holdings in the Company.

The components of total target compensation in 2010 were as follows:

	Base Salary	Short-Term Incentive	Long-Term Incentive
David R. Emery, CEO	36%	26%	38%
Anthony S. Cleberg, CFO	42%	19%	39%
Linden R. Evans, COO-Utilities	39%	20%	41%
Thomas M. Ohlmacher, COO-Non-regulated Energy	39%	19%	42%
Steven J. Helmers, Sr. Vice President and General Counsel	43%	17%	40%

The total target compensation for our Named Executive Officers in 2010 averaged 8 percent below the market median.

Base Salary. Base salaries for all officers are reviewed annually. We also adjust the base salary of our executives at the time of a promotion or change in job responsibility, as appropriate. The base salary component is compared to the median of the market data provided by the compensation consultant. The actual base salary of each officer is determined by the executive's performance, the experience level of the officer, the executive's current position in a market-based salary range, and internal pay relationships. Evaluation of 2010 base salary adjustments occurred in January 2010. The Committee approved base salary increases for our Named Executive Officers, excluding Mr. Evans, averaging 4 percent. This was the first base salary increase our Named Executive Officers had received in more than two years. Mr. Evans' base salary was increased 31 percent, reflecting the substantial impact of the acquisition of the Aquila utility properties on his job responsibilities. The acquisition more than doubled our utility assets from $830 million to $2.2 billion, tripled the number of utility employees and increased the number of state jurisdictions of our utility properties from three to seven. Base salaries were not increased in 2009, due to the difficult external economic conditions and uncertainties that existed at the time.

Short-Term Incentive. Our Short-Term Incentive Plan is designed to recognize and reward the contributions of individual executives as well as the contributions that group performance makes to overall corporate success. The program's goal for our corporate officers is based on earnings per share targets in order to closely align interests with shareholders and to foster teamwork and cooperation within the officer team. The short-term incentive, after applicable tax withholding, is distributed to the officer in the form of 50 percent stock and 50 percent cash, unless the officer has met his or her stock ownership guideline, in which case he or she may elect to receive the total award in cash, after deductions and applicable tax withholding. Target award levels are established as a percentage of each participant's base salary. A target award is comparable to the average short-term incentive payout award of the comparator group at the 50th percentile level. The actual payout will vary, based on performance, between zero and 200 percent of the individual executive's short-term incentive target award level.

The Committee approves the target level for each officer in January, which is applicable to performance in the plan year. Target levels are derived in part from competitive data provided by the compensation consultant and in part by the Committee's judgment regarding internal equity, retention and an individual executive's expected contribution to the achievement of the Company's strategic objectives. The target levels for the positions held by our Named Executive Officers in 2010 are shown below.

CEO	70%
COO-Utilities	50%
COO-Non-regulated Energy	50%
CFO	45%
Sr. Vice President and General Counsel	40%

The threshold, target and maximum payout levels for our Named Executive Officers under the 2010 Short-Term Incentive Plan are shown in the Grants of Plan Based Awards in 2010 table on page 36, under the heading "Estimated Possible Payouts Under Non-Equity Incentive Plan Awards."

Early in the first quarter, the Committee meets to establish the goals for the current plan year, to evaluate actual performance in relation to the prior year's targets and to approve the actual payment of awards related to the prior plan year. The Committee reserves the discretion to adjust any award, and will review and take into account individual performance, level of contribution, and the accomplishment of specific project goals that were initiated throughout the plan year.

Consistent with 2008 and 2009, the Committee selected for 2010 a composite earnings per share goal that is weighted 80 percent on non-energy marketing earnings per share and 20 percent on energy marketing earnings per share. The Committee chose this weighted methodology because it addresses the volatility of our energy marketing segment's earnings and the potential for this volatility to disproportionately influence bonus outcomes for participants in the Short-Term Incentive Plan, both positively and negatively, and also because many participants are not directly involved in this business segment. It also meets the objectives of the plan, including:

- aligns the interests of the plan participants and the shareholders with a corporate-wide component;
- motivates employees and supports the corporate compensation philosophy;
- easily understood and communicated to ensure "buy-in" from the participants; and
- meets the performance objectives of the plan, to achieve over time an average payout equal to market competitive levels.

The Committee approved the goals for the 2010 plan year for the corporate officers as follows:

Threshold	Non-energy Marketing Earnings Per Share Goal	Energy Marketing Earnings Per Share Goal	Payout % of Target
Minimum	$1.449	$0.360	30%
Target	$1.610	$0.400	100%
Maximum	$1.852	$0.460	200%

The target earnings per share goal for 2010 was equal to budgeted earnings per share. On January 26, 2011, the Committee approved a payout of 160 percent of target under the 2010 Short-Term Incentive Plan, comprised of a 160 percent payout (200 percent weighted 80 percent) from non-energy marketing earnings and no payout from energy marketing earnings. The actual consolidated non-energy marketing earnings for 2010 were $1.67 per share. After adjusting the earnings for the non-cash, mark-to-market loss on the forward interest rate swaps, adjusted non-energy marketing earnings were $1.92 per share. This resulted in a payout of 200 percent of target for the non-energy marketing earnings goal. Energy marketing had net income of approximately $0.09 per share in 2010, resulting in no payout for the energy marketing earnings goal. The 2010 award, after applicable tax withholding, was distributed in the form of 50 percent stock and 50 percent cash to Mr. Cleberg. Messrs. Emery, Evans, Ohlmacher and Helmers had met their stock ownership guidelines and elected to receive their 2010 award in the form of 100 percent cash. Awards for corporate officers under the Short-Term Incentive Plan have varied significantly over the last five years, as shown below.

Plan Year	Payout % of Target
2010	160%
2009	56%
2008	52%
2007	200%
2006	150%

Actual awards made to each of our Named Executive Officers under the Short-Term Incentive Plans for 2010 are included in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 34.

Long-Term Incentive. Long-term incentive compensation is comprised of grants made by the Committee under our 2005 Omnibus Incentive Plan ("Omnibus Incentive Plan") which was previously approved by our shareholders. Long-term incentive compensation is intended to:

- promote corporate goals by linking the personal interests of participants to those of our shareholders;
- provide participants with an incentive for excellence in individual performance;
- promote teamwork among participants; and
- provide flexibility in our effort to motivate, retain, and attract the services of participants who make significant contributions to our success by allowing participants to share in such success.

The Committee oversees the administration of the Omnibus Incentive Plan with full power and authority to determine when and to whom awards will be granted, along with the type, amount and other terms and conditions of each award. The long-term incentive compensation component is currently composed of restricted stock (or restricted stock units if the executive elects to defer the compensation) and performance shares. The Committee chose these components because linking executive compensation to stock price appreciation and total shareholder return is an effective way to align the interests of management with those of our shareholders. The Committee selected total shareholder return as the performance goal for the performance shares because it believes executive pay under a long-term, capital accumulation program should mirror our performance in shareholder return as compared to our peer group of companies.

The value of long-term incentives awarded is based primarily on competitive market-based data presented by the compensation consultant to the Committee, the impact each position has on our shareholder return and internal pay relationships. The Committee approved the target long-term incentive compensation level for each officer in January.

Long-term incentive compensation approved for the 2010 plan year for our Named Executive Officers is shown in the table below.

	Long-Term Incentive Value	Percentage of Base Salary
David R. Emery, CEO	$630,000	105%
Anthony S. Cleberg, CFO	$300,000	92%
Linden R. Evans, COO-Utilities	$380,000	106%
Thomas M. Ohlmacher, COO-Non-regulated Energy	$380,000	107%
Steven J. Helmers, Sr. Vice President and General Counsel	$260,000	93%

The variance in percentage of base salary for the long-term incentive value of our Named Executive Officers reflects our philosophy that the CEO and COOs should have more of their total compensation at risk because they hold positions that have a greater impact on our long-term results. The long-term incentive value for these positions normally approximate 105 percent of base salary.

Restricted stock (or restricted stock units) is used to deliver 50 percent of the long-term incentive award amounts, with the remaining 50 percent delivered in the form of performance shares. The actual shares of restricted stock and performance shares granted in 2010 are reflected in the tables in the *Restricted Stock and Restricted Stock Units* and *Performance Shares* sections that follow.

Restricted Stock and Restricted Stock Units. Restricted stock and restricted stock units vest one-third each year over a three-year period, and automatically vest in their entirety upon death, disability or a change in control. Dividends are paid on the restricted shares and dividend equivalents accrue on restricted stock units. Unvested restricted stock or units are forfeited if an officer's employment is terminated for any reason other than death, disability or in the event of a change in control. Corporate officers may elect to receive the award in the form of restricted stock, or to defer the payment under the Nonqualified Deferred Compensation Plan, in the form of restricted stock units. The number of shares awarded in 2010 for each of our Named Executive Officers is shown below and is included in the Grants of Plan Based Awards in 2010 table under the heading "All Other Stock Awards: Number of Shares of Stock or Units" and "Grant Date Fair Value of Stock Awards" on page 36.

David R. Emery, CEO	12,064
Anthony S. Cleberg, CFO	5,745
Linden R. Evans, COO-Utilities	7,277
Thomas M. Ohlmacher, COO-Non-regulated Energy	7,277
Steven J. Helmers, Sr. Vice President and General Counsel	4,979

Performance Shares. Participants are awarded a target number of performance shares based upon the value of the individual performance share component approved by the Committee, divided by the Beginning Stock Price. The Beginning Stock Price, as defined under the Performance Plan, is the average of the closing price of our common stock for the 20 trading days immediately preceding the beginning of the plan period. Entitlement to performance shares is based on our total shareholder return over designated performance periods, as measured against our peer group. The peer group for the performance plan is the same as our peer group used for our market compensation analysis and is listed on page 23. In addition, in order for any performance shares to be awarded, our stock price must also increase during the performance period from the Beginning Stock Price for the performance periods that began in 2008 and 2009. For the performance period that began in 2010, the Committee modified the plan, whereby the Ending Stock Price must be at least equal to 75 percent of the Beginning Stock Price, in order for any performance shares to be awarded. The final value of the performance shares is based upon the number of shares of common stock that are ultimately granted, based upon our performance in relation to the performance criteria. At the end of each respective performance period, actual awards may range from 0 percent to 175 percent of the target share amounts plus accrued dividends. A 100 percent payout of the target shares occurs if our total shareholder return exceeds the 50th percentile of the peer group. A zero percent payout occurs if we are below the 40th percentile and a maximum payout of 175 percent occurs if we perform at the 80th percentile or above. The performance awards and dividend equivalents, if earned, are paid in 50 percent cash and 50 percent common stock. All payroll deductions and applicable tax withholding related to the award are withheld from the cash portion. Performance share target grant values for new performance periods are approved in January of each year.

Each performance share period extends for three years. For the recently completed performance period, January 1, 2008 to December 31, 2010, our total shareholder return was negative 20 percent, which ranked at the 15th percentile of our peer group, resulting in no payout. Several factors significantly impacted our financial performance, including a dramatic decrease in natural gas prices from mid-2008 levels and impacts from the global economic crisis that commenced in late 2008.

Actual awards for the corporate officers under the Performance Share Plan over the last five years have varied significantly based on the Company's performance in relation to its peer group as shown below.

Performance Period	Payout % of Target
January 1, 2008 to December 31, 2010	0
January 1, 2007 to December 31, 2009	0
January 1, 2006 to December 31, 2008	0
January 1, 2005 to December 31, 2007	175
March 1, 2004 to December 31, 2006	37

Target shares for each of our Named Executive Officers for the outstanding performance periods are as follows:

	January 1, 2009 to December 31, 2011 Performance Period	January 1, 2010 to December 31, 2012 Performance Period	January 1, 2011 to December 31, 2013 Performance Period
David R. Emery	12,319	11,982	13,162
Anthony S. Cleberg	5,866	5,706	5,758
Linden R. Evans	7,431	7,227	6,581
Thomas M. Ohlmacher *	5,573	3,011	—
Steven J. Helmers	5,084	4,945	4,442

* Mr. Ohlmacher retired on March 31, 2011; therefore he is not a participant in the January 1, 2011 to December 31, 2013 performance period and the target shares for the January 1, 2009 to December 31, 2011 and January 1, 2010 to December 31, 2012 performance periods have been pro-rated for his time served during the performance period.

Actual payouts, if any, will be determined based upon our total shareholder return for the plan period in comparison to our peer group.

Performance Evaluation

Role of Executive Officers in Compensation Decisions. The CEO annually reviews the performance of each of our senior officers and presents a summary of his evaluations to the Committee. Based upon these performance reviews, market analysis conducted by compensation consultants and discussions with our Chief Human Resources Officer, the CEO recommends the compensation for this group of officers to the Committee.

Role of the Committee and Board in Setting Executive Compensation. At the beginning of each year, the Committee reviews and establishes the corporation's financial targets and the CEO's goals and objectives for the year. At the end of each year, the Committee evaluates the CEO's performance in light of established goals and objectives, with input from the other independent directors. Based upon the Committee's evaluation and recommendation, the independent directors of the Board set the CEO's annual compensation, including salary, short-term incentive, long-term incentive and equity compensation.

The Committee reviews the CEO's evaluation of the performance of our senior officers and approves his compensation recommendations for this group of officers. The Committee may exercise its discretion in modifying any of the recommended compensation and award levels in its review and approval process. The Committee is required to approve all decisions regarding equity awards to our officers.

Stock Ownership Guidelines

The Committee has implemented stock ownership guidelines that apply to all officers based upon their level of responsibility. We believe it is important for our officers to hold a significant amount of our common stock to further align their performance with the interest of our shareholders. A "retention ratio" approach to stock ownership is incorporated into the guidelines. This approach requires officers to retain 100 percent of all shares owned, including shares awarded through our incentive plans (net of share withholding for taxes and in the case of cashless stock option exercises, net of the exercise price and withholding for taxes) until specific ownership goals are achieved. Ownership guidelines are denominated in share amounts which approximate a multiple of base pay.

The ownership guidelines by officer level are as follows:

Officer Level	Ownership Guideline (# of Shares)
CEO	90,000
COOs and CFO	40,000
Vice President and General Manager of Energy Marketing	40,000
Other Senior Executive Officers	25,000
Other Corporate Officers and Business Unit Leaders	10,000
Other Subsidiary Officers	5,000

The ownership guidelines and current stock ownership of our Named Executive Officers as of March 31, 2011, are shown below.

Officer Level	Ownership Guideline (# of Shares)	Actual Ownership (# of Shares)	Years in Position
David R. Emery, CEO	90,000	111,954	7
Anthony S. Cleberg, CFO	40,000	32,817	2.5
Linden R. Evans, COO-Utilities	40,000	46,217	6
Thomas M. Ohlmacher, COO-Non-regulated Energy	40,000	47,449	9
Steven J. Helmers, Sr. Vice President and General Counsel	25,000	41,045	10

2010 Benefits

Perquisites and Other Personal Benefits. We provide a limited number of market-based perquisites to our executive officers, including personal use of a Company vehicle. The total value of these perquisites in 2010 did not exceed $9,000 for any one of our Named Executive Officers. The specific amounts attributable to perquisites for 2010 are disclosed in the Summary Compensation Table on page 34. The Committee periodically reviews the perquisites and other personal benefits provided to our executive officers and believes the current perquisites are reasonable and consistent with our overall compensation program.

Retirement and Other Benefits. We maintain a variety of employee benefit plans and programs in which our executive officers may participate. We believe it is important to provide post-employment benefits to our executive officers and the benefits we provide approximate retirement benefits paid by other employers to executives in similar positions. The Committee periodically reviews the benefits provided, with assistance from its compensation consultant, to maintain a market-based benefits package.

Effective January 1, 2010, the Company adopted a defined contribution plan design as our primary retirement plan and amended our Defined Benefit Pension Plan ("Pension Plan") for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with the Company as of January 1, 2010. Each of our Named Executive Officers are participants in the Pension Plan. Messrs. Emery and Ohlmacher met the age and years of service requirement and elected to stay with the existing Pension Plan. Messrs. Cleberg, Evans and Helmers did not meet the age and service requirement, therefore their Pension Plan benefit was frozen as of January 1, 2010, and they now receive Company Retirement Contributions ("Retirement

Contributions") in the Retirement Savings Plan. The Retirement Contributions is an age and service points-based calculation.

The Black Hills Corporation 401(k) Retirement Savings Plan is offered to all eligible employees of the Company and its subsidiaries. All of our Named Executive Officers are participants in the Black Hills Corporation 401(k) Retirement Savings Plan. Participants may elect to invest up to 50 percent of their eligible compensation on a combined pre-tax and/or after-tax basis up to maximum amounts established by the Internal Revenue Service. The Company provides for matching contributions and Retirement Contributions for certain eligible participants. Vesting of Company contributions ranges from immediate vesting to graduated vesting at 20 percent per year with full vesting when the participant has five years of service with the Company. All of our Named Executive Officers received matching contributions in 2010. Messrs. Cleberg, Evans and Helmers also received Retirement Contributions since their Pension Plan benefits were frozen. The matching contributions and the Retirement Contributions are included as "All Other Compensation" in the Summary Compensation Table on page 34.

The Pension Plan, Retirement Contributions and matching contributions are limited by the Internal Revenue Code in the amount of compensation that can be taken into account in determining contributions and benefits, and in the case of the Pension Plan, the amount of annual payments received under the plan. Because of these limitations we also have the Nonqualified Pension Plans and the Nonqualified Deferred Compensation Plan. The Nonqualified Pension Plans include our Grandfathered Pension Equalization Plan, 2005 Pension Equalization Plan, Pension Restoration Plan and prior to its elimination on January 1, 2010, the 2007 Pension Equalization Plan. Messrs. Emery, Ohlmacher and Helmers are participants in the Grandfathered Pension Equalization Plan and the 2005 Pension Equalization Plan. Messrs. Cleberg and Evans were participants in the 2007 Pension Equalization Plan prior to its elimination. All of the Named Executive Officers are participants in the Pension Restoration Plan.

As a result of the change in the Pension Plan, the benefits for certain officers (including Messrs. Cleberg, Evans and Helmers) under the Nonqualified Pension Plans were significantly reduced because the nonqualified benefit calculations were linked to the benefits earned in the Pension Plan. To overcome this deficit, the Committee eliminated the 2007 Pension Equalization Plan and amended the Nonqualified Deferred Compensation Plan to provide non-elective nonqualified restoration benefits to those affected officers who were not eligible to continue accruing benefits under the Pension Plan and associated Nonqualified Pension Plans. The amended Nonqualified Deferred Compensation Plan provides the affected officers with non-elective supplemental matching contributions equal to six percent of eligible compensation in excess of the Internal Revenue Code limit plus matching contributions, if any, lost under the 401(k) Retirement Savings Plan due to nondiscrimination test results and provides non-elective supplemental points-based contributions that cannot be made to the 401(k) Retirement Savings Plan due to the Internal Revenue Code limit. It also provides supplemental target contributions equal to a percentage of compensation that may differ by executive, based on the executive's current age and length of service with the Company, as determined by the Plan's actuary.

The level of retirement benefits provided by the Pension Plan and Nonqualified Plans for each of our Named Executive Officers is reflected in the Pension Benefits for 2010 table on page 39. The Company's contributions to the Nonqualified Deferred Compensation Plan are included in the Other Compensation column of the Summary Compensation Table on page 34 and the aggregate Nonqualified Deferred Compensation balance at December 31, 2010 is reported in the Nonqualified Deferred Compensation for 2010 table on page 42. These retirement benefits are explained in more detail in the accompanying narrative to the tables.

Change in Control Payments

Our Named Executive Officers may also receive severance benefits in the event of a change in control. Change in control agreements are common among our peer group and the Committee and our Board of Directors believe providing these agreements to our corporate officers protects our shareholder interests in the event of a change in control by helping assure management focus and continuity. Our change in control agreements have expiration dates and our Board of Directors conducts a thorough review of the change in control agreements at each renewal period. In 2010, new change in control agreements were entered into to reflect the retirement plan changes that were effective January 1, 2010. In addition, the excise tax gross-up provision that existed in the prior agreements was removed from the new agreements. The new change in control agreements expire November 15, 2013. In general, our change in control agreements provide a severance payment of up to 2.99 times average compensation for our CEO, and up to two times average compensation for the other Named Executive Officers. The change in control agreements contain a "double trigger," providing benefits in association with a change in control only upon:

(i) termination of employment other than by death, disability or by the Company for cause, or

(ii) a termination by the employee for good reason.

See the Potential Payments Upon Termination or Change in Control table on page 43 and the accompanying narrative for more information regarding our change in control agreements and estimated payments associated with a change in control.

Tax and Accounting Implications

Section 162(m) of the U.S. Internal Revenue Code of 1986, as amended, limits the tax deductibility by a corporation of compensation in excess of $1 million paid to certain of its officers. Compensation which qualifies as "performance-based" is excluded from the $1 million limit, if, among other requirements, the compensation is payable only upon attainment of pre-established, objective performance goals under a plan approved by the corporation's shareholders. As a result, the Compensation Committee has designed a large share of our incentive compensation for our Named Executive Officers to qualify for the exemption of "performance-based" compensation from the deductibility limit. However, the Compensation Committee does have the discretion to design and use compensation elements that may not be deductible under Section 162(m) if it determines those elements are in line with competitive practice, our compensation philosophy, and our best interests. We believe the compensation paid to our Named Executive Officers in 2010 is fully deductible.

Clawback Policy

We have a policy that if an accounting restatement occurs after incentive payments have been made, due to the results of misconduct associated with financial reporting, the Committee will seek repayment of the incentive compensation from our CEO and CFO, and has the discretion to request repayment of incentive compensation from our other officers, taking into consideration the individual roles and responsibilities prompting the restatement.

In addition, effective beginning with 2009 award agreements for restricted stock and target performance shares we have included clawback provisions whereby the participant may be required to repay all income or gains previously realized in respect of such awards if their employment is terminated for cause, or within one year following termination of employment, the Board determines that the participant engaged in conduct prior to their termination that would have constituted the basis for a termination of employment for cause.

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Company's Board of Directors that the Compensation Discussion and Analysis be included in this Proxy Statement.

THE COMPENSATION COMMITTEE

Jack W. Eugster, Chairperson
David C. Ebertz
Kay S. Jorgensen
Stephen D. Newlin
Thomas J. Zeller

SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the fiscal years ended December 31, 2010, 2009 and 2008. We have no employment agreements with our Named Executive Officers. Mr. Cleberg joined us on July 16, 2008.

Name and Principal Position	Year	Salary	Stock Awards(1)	Non-Equity Incentive Plan Compensation(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(3)	All Other Compensation(4)	Total
David R. Emery	2010	$588,924	$605,554	$672,000	$766,046	$ 60,138	$2,692,662
Chairman, President	2009	$564,000	$674,723	$221,088	$361,799	$ 51,990	$1,873,600
and Chief Executive Officer	2008	$563,269	$867,400	$205,296	$549,730	$ 42,293	$2,227,988
Anthony S. Cleberg	2010	$321,923	$288,372	$234,000	—	$149,607	$ 993,902
Executive Vice President	2009	$315,000	$321,300	$ 79,380	$102,058	$198,778	$1,016,516
and Chief Financial Officer	2008	$130,846	$225,000	$ 34,020	$ 3,645	$ 25,911	$ 419,422
Linden R. Evans	2010	$333,538	$365,257	$288,000	—	$148,397	$1,135,192
President and Chief	2009	$274,000	$406,978	$ 76,720	$102,553	$ 29,086	$ 889,337
Operating Officer—Utilities	2008	$273,212	$395,908	$ 71,240	$125,292	$ 24,421	$ 890,073
Thomas M. Ohlmacher	2010	$353,769	$365,257	$284,000	$734,583	$ 43,383	$1,780,992
President and Chief	2009	$351,000	$406,978	$ 98,280	$312,019	$ 35,125	$1,203,402
Operating Officer— Non-regulated Energy	2008	$350,600	$466,020	$ 91,260	$292,809	$ 28,915	$1,229,604
Steven J. Helmers	2010	$276,923	$249,918	$179,200	$178,390	$ 74,271	$ 958,702
Senior Vice President	2009	$270,000	$278,462	$ 76,720	$113,474	$ 26,231	$ 764,887
and General Counsel	2008	$269,604	$265,550	$ 49,140	$121,460	$ 21,648	$ 727,402

(1) Stock Awards represent the grant date fair value related to restricted stock, restricted stock units and performance shares that have been granted as a component of Long-Term Incentive Compensation. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 11 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2010. The amount included for performance shares is based on the level the award is expected to payout. If the award were based on the maximum payout level, the amounts for the Stock Awards column would be increased to the following amounts:

	2010	2009	2008
David R. Emery	$823,477	$944,509	$1,105,450
Anthony S. Cleberg	$392,150	$449,766	$ 225,000
Linden R. Evans	$496,698	$569,717	$ 490,714
Thomas M. Ohlmacher	$496,698	$569,717	$ 616,785
Steven J. Helmers	$339,854	$389,802	$ 329,375

(2) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Annual Incentive Plan. The Compensation Committee approved the payout of the 2010 awards at its January 26, 2011, meeting and the awards were paid on March 4, 2011.

(3) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Defined Benefit Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective year.

The Defined Benefit Pension Plan and PRB were frozen as of December 31, 2009 for participants that did not satisfy the age 45 and 10 years of service eligibility. Messrs. Cleberg, Evans and Helmers did not meet the eligibility choice criteria and their Defined Pension and PRB benefits were frozen. In 2008, Mr. Cleberg did not meet the one year service requirement to be in the Defined Benefit Plan. The amounts for 2008 were annualized due to the change in ASC 715 measurement date. The change in present value of the accumulated benefit from September 30, 2007 to December 31, 2008 has been multiplied by 12/15ths to determine a twelve month value (except for Mr. Cleberg who did not accrue benefits for the entire 15 month period).

The PEP is offered through the Grandfathered Pension Equalization Plan ("Grandfathered PEP"), 2005 Pension Equalization Plan ("2005 PEP") and 2007 Pension Equalization Plan ("2007 PEP"). Messrs. Emery, Ohlmacher and Helmers are participants in the Grandfathered PEP and 2005 PEP. The 2007 PEP was eliminated effective January 1, 2010 and was replaced with employer contributions into a Nonqalified Deferred Compensation Plan ("NQDC"). The NQDC employer contributions are reported in the All Other Compensation column. Messrs. Cleberg and Evans were the only Named Executive Officers participating in the 2007 PEP.

No Named Executive Officer received preferential or above-market earnings on nonqualified deferred compensation. The value attributed from each plan to each Named Executive Officer is shown in the table below.

	Year	Defined Benefit Plan	PRB	PEP	Total Change in Pension Value
David R. Emery	2010	$ 88,118	$369,162	$ 308,766	$766,046
	2009	$ 43,690	$167,024	$ 151,085	$361,799
	2008	$ 33,858	$264,299	$ 251,573	$549,730
Anthony S. Cleberg	2010	$ 3,713	$ 2,660	$ (52,506)	—
	2009	$ 36,790	$ 12,762	$ 52,506	$102,058
	2008	—	$ 3,645	—	$ 3,645
Linden R. Evans	2010	$ 22,976	$ 19,195	$(163,783)	—
	2009	$ 25,375	$ 24,629	$ 52,549	$102,553
	2008	$ 19,368	$ 48,132	$ 57,792	$125,292
Thomas M. Ohlmacher	2010	$218,327	$323,252	$ 193,004	$734,583
	2009	$131,901	$ 96,327	$ 83,791	$312,019
	2008	$101,389	$109,258	$ 82,162	$292,809
Steven J. Helmers	2010	$ 28,263	$ 18,239	$ 131,888	$178,390
	2009	$ 34,129	$ 18,295	$ 61,050	$113,474
	2008	$ 26,157	$ 22,526	$ 72,777	$121,460

(4) All Other Compensation includes amounts allocated under the 401(k) match, defined contributions, NQDC contributions, dividends received on restricted stock and unvested restricted stock units and perquisites. Mr. Cleberg's 2008 and 2009 perquisites also include temporary living, travel and other relocation expenses, including an $89,050 loss on the sale of his home in 2009.

	Year	401(k) Match	Defined Contri-bution	NQDC Contri-bution	Dividends on Restricted Stock/Units	Perquisites	Total Other Compensation
David R. Emery	2010	$14,700	—	—	$37,378	$8,060	$ 60,138
Anthony S. Cleberg	2010	$14,700	$7,350	$100,347	$18,484	$8,726	$149,607
Linden R. Evans	2010	$14,700	$7,350	$ 96,925	$21,824	$7,598	$148,397
Thomas M. Ohlmacher	2010	$14,700	—	—	$20,989	$7,694	$ 43,383
Steven J. Helmers	2010	$14,700	$7,350	$ 31,935	$14,859	$5,427	$ 74,271

GRANTS OF PLAN BASED AWARDS IN 2010(1)

Name	Grant Date	Date of Compensation Committee Action	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(2) Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards(3) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units(4) (#)	Grant Date Fair Value of Stock Awards(5) ($)
David R. Emery			$126,000	$420,000	$840,000					
	1/27/10	1/27/10				5,991	11,982	20,969		$290,564
	2/01/10	1/27/10							12,064	$314,991
Anthony S. Cleberg			$ 43,875	$146,250	$292,500					
	1/27/10	1/27/10				2,853	5,706	9,986		$138,371
	2/01/10	1/27/10							5,745	$150,002
Linden R. Evans			$ 54,000	$180,000	$360,000					
	1/27/10	1/27/10				3,614	7,227	12,647		$175,255
	2/01/10	1/27/10							7,277	$190,002
Thomas M. Ohlmacher			$ 53,250	$177,500	$355,000					
	1/27/10	1/27/10				3,614	7,227	12,647		$175,255
	2/01/10	1/27/10							7,277	$190,002
Steven J. Helmers			$ 33,600	$112,000	$224,000					
	1/27/10	1/27/10				2,473	4,945	8,654		$119,916
	2/01/10	1/27/10							4,979	$130,002

(1) No stock options were granted to our Named Executive Officers in 2010.

(2) The columns under "Estimated Possible Payouts Under Non-Equity Incentive Plan Awards" show the range of payouts for 2010 performance under our Short-Term Incentive Plan as described in the Compensation Discussion and Analysis under the section titled "Short-Term Incentive" on page 24. If the performance criteria are met, payouts can range from 30 percent of target at the threshold level to 200 percent of target at the maximum level. The 2011 bonus payment for 2010 performance has been made based on achieving the criteria described in the Compensation Discussion and Analysis, at 160 percent of target, and is shown in the Summary Compensation Table on page 34 in the column titled "Non-Equity Incentive Plan Compensation."

(3) The columns under "Estimated Future Payouts Under Equity Incentive Plan Awards" show the range of payouts (in shares of stock) for the January 1, 2010 to December 31, 2012 performance period as described in the Compensation Discussion and Analysis under the section titled "Long-Term Incentive—*Performance Shares*" on page 27. If the performance criteria are met, payouts can range from 50 percent of target to 175 percent of target. If a participant retires, suffers a disability or dies during the performance period, the participant or the participant's estate is entitled to that portion of the number of performance shares as such participant would have been entitled to had he or she remained employed, prorated for the number of months served. Performance shares are forfeited if employment is terminated for any other reason. During the performance period, dividends and other distributions paid with respect to the shares of common stock shall accrue for the benefit of the participant and are paid out at the end of the performance period.

(4) The column "All Other Stock Awards" reflects the number of shares of restricted stock granted on February 1, 2010 under our 2005 Omnibus Incentive Plan. The restricted stock vests one-third a year over a three-year period, and automatically vests upon death, disability or a change in control. Unvested restricted stock is forfeited if employment is terminated for any other reason. Dividends are paid on the restricted shares and the dividends that were paid in 2010 are included in the column titled "All Other Compensation" in the Summary Compensation Table on page 34.

(5) The column "Grant Date Fair Value of Stock Awards" reflects the grant date fair value of each equity award computed in accordance with the provisions of accounting standards for stock compensation. The grant date fair value for the performance shares was $24.25 per share and was calculated using a Monte Carlo simulation model. Assumptions used in the calculation are included in Note 11 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2010. The grant date fair value for the restricted stock was $26.11 per share for the February 1, 2010 grant which was the market value of our common stock on the date of grant as reported on the New York Stock Exchange.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2010(1)

	Option Awards			Stock Awards			
Name	Number of Securities Underlying Unexercised Options Exercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested(2) (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(2) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
David R. Emery	5,000	$55.36	5/30/11	24,688	$740,640	27,129	$813,840
	4,595	$35.10	4/23/12				
	7,500	$27.49	3/31/13				
	13,787	$28.09	5/15/13				
Anthony S. Cleberg	—	—	—	11,694	$350,820	12,919	$387,555
Linden R. Evans	2,000	$32.34	6/17/12	14,394	$431,820	16,363	$490,883
	3,000	$25.16	12/10/12				
	5,000	$29.83	12/31/13				
Thomas M. Ohlmacher	2,500	$55.36	5/30/11	14,195	$425,850	16,363	$490,883
Steven J. Helmers	9,000	$55.36	5/30/11	9,811	$294,330	11,196	$335,873
	10,110	$35.10	4/23/12				

(1) There were no unexercisable stock options or unexercised unearned options under equity incentive plans outstanding at December 31, 2010 for our Named Executive Officers.

(2) Vesting dates for restricted stock, restricted stock units and performance shares are shown in the table below. The performance shares shown with a vesting date of December 31, 2010, reflect no payout for the performance period ended December 31, 2010. On January 26, 2011 the Compensation Committee confirmed that the performance criteria were not met and there would be no payout. The performance shares with a vesting date of December 31, 2011 are shown at the threshold payout level and the performance shares with a vesting date of December 31, 2012 are shown at a maximum payout level, based upon the performance as of December 31, 2010.

	Unvested Restricted Stock and Restricted Stock Units		Unvested and Unearned Performance Shares	
Name	# of Shares	Vesting Date	# of Shares	Vesting Date
David R. Emery	3,848	1/02/11	—	12/31/10
	2,390	1/04/11	6,160	12/31/11
	4,021	2/01/11	20,969	12/31/12
	2,538	8/13/11		
	3,848	1/02/12		
	4,021	2/01/12		
	4,022	2/01/13		
Anthony S. Cleberg	1,832	1/02/11	2,933	12/31/11
	1,915	2/01/11	9,986	12/31/12
	2,284	8/13/11		
	1,833	1/02/12		
	1,915	2/01/12		
	1,915	2/01/13		
Linden R. Evans	2,321	1/02/11	—	12/31/10
	952	1/04/11	3,716	12/31/11
	2,425	2/01/11	12,647	12/31/12
	1,523	8/13/11		
	2,321	1/02/12		
	2,426	2/01/12		
	2,426	2/01/13		

Name	Unvested Restricted Stock and Restricted Stock Units		Unvested and Unearned Performance Shares	
	# of Shares	Vesting Date	# of Shares	Vesting Date
Thomas M. Ohlmacher	2,321	1/02/11	—	12/31/10
	1,514	1/04/11	3,716	12/31/11
	2,425	2/01/11	12,647	12/31/12
	762	8/13/11		
	2,321	1/02/12		
	2,426	2/01/12		
	2,426	2/01/13		
Steven J. Helmers	1,588	1/02/11	—	12/31/10
	641	1/04/11	2,542	12/31/11
	1,659	2/01/11	8,654	12/31/12
	1,015	8/13/11		
	1,588	1/02/12		
	1,660	2/01/12		
	1,660	2/01/13		

OPTION EXERCISES AND STOCK VESTED DURING 2010

Name	Option Awards		Stock Awards(1)	
	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
David R. Emery	—	—	11,517	$317,574
Anthony S. Cleberg	—	—	4,116	$120,047
Linden R. Evans	—	—	5,869	$162,973
Thomas M. Ohlmacher	—	—	6,302	$170,857
Steven J. Helmers	—	—	4,014	$111,321

(1) Reflect restricted stock that vested in 2010.

PENSION BENEFITS FOR 2010

Pension benefits for our Named Executive Officers in 2010 were comprised of a qualified defined benefit pension, a nonqualified pension restoration benefit and a supplemental pension benefit. None of our Named Executive Officers received any pension benefit payments during the fiscal year ended December 31, 2010.

Effective January 1, 2010, the Company adopted a defined contribution plan design as our primary retirement plan and amended our Pension Plan and Nonqualified Pension Plans for all eligible employees to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with the Company as of January 1, 2010.

Name	Plan Name	Number of Years of Credited Service(1) (#)	Present Value of Accumulated Benefit(2) ($)
David R. Emery	Defined Benefit Pension Plan	21.33	$ 368,527
	Pension Restoration Benefit	21.33	$1,289,467
	Grandfathered Pension Equalization Plan	16.00	$ 455,498
	2005 Pension Equalization Plan	16.00	$ 956,489
Anthony S. Cleberg	Defined Benefit Pension Plan	1.42	$ 40,503
	Pension Restoration Benefit	1.42	$ 19,067
Linden R. Evans	Defined Benefit Pension Plan	8.58	$ 130,760
	Pension Restoration Benefit	8.58	$ 103,989
Thomas M. Ohlmacher	Defined Benefit Pension Plan	36.50	$1,229,147
	Pension Restoration Benefit	36.50	$1,757,893
	Grandfathered Pension Equalization Plan	19.00	$1,303,896
	2005 Pension Equalization Plan	19.00	$ 134,142
Steven J. Helmers	Defined Benefit Pension Plan	8.92	$ 187,555
	Pension Restoration Benefit	8.92	$ 115,749
	Grandfathered Pension Equalization Plan	9.00	$ 126,126
	2005 Pension Equalization Plan	9.00	$ 636,281

(1) The number of years of credited service represents the number of years used in determining the benefit for each plan. The Pension Equalization Plans are not directly tied to service but rather the number of years of participation in the plan.

(2) The present value of accumulated benefits was calculated assuming benefits commence at age 62 and using the discount rate, mortality rate and assumed payment form assumptions consistent with those disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2010.

Defined Benefit Pension Plan

We have a Pension Plan, a qualified pension plan, in which all of our Named Executive Officers are included. As discussed above, effective January 1, 2010, we amended our Pension Plan to incorporate a partial freeze in which the accrual of benefits ceased for certain participants while other participants were allowed an election to continue to accrue benefits. Employees eligible to elect continued participation were those employees who were at least 45 years old and had at least 10 years of eligible service with the Company as of January 1, 2010. Messrs. Emery and Ohlmacher met the age and years of service requirement and elected to continue with the existing plan.

Participants who did not meet the age and years of service requirement as of January 1, 2010, had their pension benefit frozen as of December 31, 2009 and effective January 1, 2010 began to receive an additional age and service points-based employer contribution under the 401(k) retirement savings plan. Messrs. Cleberg, Evans and Helmers had their pension benefits frozen as of December 31, 2009, and began receiving the additional age and service points-based employer contribution effective January 1, 2010.

The Pension Plan provides benefits at retirement based on length of employment service and average compensation levels during the highest five consecutive years of the last ten years of service. For purposes of the benefit calculation, earnings include wages and other cash compensation received from the Company, including any bonus, commission, unused paid time off or incentive compensation. It also includes any elective before-tax contributions made by the employee to a Company sponsored cafeteria plan or 401(k) plan. However, it does not include any expense reimbursements, taxable fringe benefits, moving expenses or moving/relocation allowances, nonqualified deferred compensation, non-cash incentives, stock options and any payments of long-term incentive compensation such as restricted stock or payments under performance share plans. The Internal Revenue Code places maximum limitations on the amount of compensation that may be recognized when determining benefits of qualified pension plans. In 2010, the maximum amount of compensation that could be recognized when determining compensation was $245,000 (called "covered compensation").

The benefit formula for the Named Executive Officers is the sum of (a) and (b) below.

(a) Credited Service after January 31, 2000

0.9% of average earnings (up to covered compensation), multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000	Plus	1.3% of average earnings in excess of covered compensation, multiplied by credited service after January 31, 2000 minus the number of years of credited service before January 31, 2000

Plus

(b) Credited Service before January 31, 2000

1.2% of average earnings (up to covered compensation), multiplied by credited service before January 31, 2000	Plus	1.6% of average earnings in excess of covered compensation, multiplied by credited service before January 31, 2000

Pension benefits are not reduced for social security benefits. The Internal Revenue Code places maximum limitations on annual benefit amounts that can be paid under qualified pension plans. In 2010, the maximum benefit payable under qualified pension plans was $195,000. Accrued benefits become 100 percent vested after an employee completes five years of service. None of our Named Executive Officers have been credited with extra years of credited service under the plan.

Normal retirement is defined as age 65 under the plan, however a participant may begin taking unreduced benefits at age 62 with five years of service. Participants who have completed at least five years of credited service can retire and receive defined benefit pension benefits as early as age 55, however the retirement benefit will be reduced by five percent for each year of retirement before age 62. For example, a participant with at least five years of credited service may retire at age 55 and receive a pension benefit equal to 65 percent of the normal retirement benefit. Mr. Ohlmacher is currently age 59 and is entitled to early retirement benefits under this provision.

If a participant is vested and leaves the Company before reaching his or her earliest retirement date, he or she may begin receiving the full value of his or her vested benefit at age 65 or can receive a reduced benefit as early as age 55 if he or she has at least five years of credited service when he or she leaves employment of the Company. The benefit will be reduced by five percent for each year he or she begins receiving benefits prior to age 65. For example, a participant who leaves the Company before reaching age 55 with at least five years of credited service may begin receiving benefits at age 55 equal to 50 percent of the normal retirement benefit and may begin receiving retirement benefits at age 65 on an unreduced basis.

If a participant is single, the benefit is paid as a life annuity. If a participant is married, the benefit is paid as a joint and 50 percent survivor annuity unless an optional form of payment is chosen.

Our employees do not contribute to the plan. The amount of the annual contribution by us to the plan is based on an actuarial determination.

Pension Equalization Plans and Pension Restoration Benefit

We also have a Grandfathered Pension Equalization Plan, a 2005 Pension Equalization Plan and a Pension Restoration Benefit, nonqualified supplemental plans, in which benefits are not tax deductible until paid. Prior to January 1, 2010, we also had a 2007 Pension Equalization Plan. The plans are designed to provide the higher paid executive employee a retirement benefit which, when added to social security benefits and the pension to be received under the Defined Benefit Pension Plan, will approximate retirement benefits being paid by other employers to their employees in similar executive positions. The employee's pension from the qualified pension plan is limited by the Internal Revenue Code. The 2010 limit was set at $195,000 annually and the compensation taken into account in determining contributions and benefits could not exceed $245,000 and could not include nonqualified deferred compensation. The amount of deferred compensation paid under nonqualified plans is not subject to these limits.

As a result of the change in the Pension Plan effective January 1, 2010, the benefits for certain officers (including Messrs. Cleberg, Evans and Helmers) under the Nonqualified Pension Plans were significantly reduced because the nonqualified benefit calculations were linked to the benefits earned in the Pension Plan. As a result of those amendments, effective January 1, 2010, the Compensation Committee eliminated the 2007 Pension Equalization Plan and amended the Nonqualified Deferred Compensation Plan to provide non-elective nonqualified restoration benefits to those affected officers who were not eligible to continue accruing benefits under the Pension Plan and associated Nonqualified Pension Plans.

Grandfathered Pension Equalization Plan and 2005 Pension Equalization Plan. The Grandfathered Pension Equalization Plan provides the pension equalization benefits to each participant who had earned and vested benefits before January 1, 2005, and is not subject to the provisions of Section 409A of the Internal Revenue Code. The 2005 Pension Equalization Plan provides the pension equalization benefits to each participant that were earned and vested on or after January 1, 2005, and is subject to the provisions of Section 409A.

Participants were designated by our Board of Directors upon recommendation of the CEO. These plans have been frozen to new participants since 2002. A participant under the Grandfathered and 2005 Pension Equalization Plans does not qualify for benefits until the benefits become vested under a defined vesting schedule. A participant is fully vested after eight years of employment under the plan. Messrs. Emery, Ohlmacher and Helmers are fully vested participants in the Grandfathered and 2005 Pension Equalization Plans. Messrs. Cleberg and Evans are not participants in these plans.

The annual benefit is 25 percent of the employee's average earnings, if salary was less than two times the Social Security Wage Base, or 30 percent, if salary was more than two times the Social Security Wage Base, multiplied by the vesting percentage. Average earnings are normally an employee's average earnings for the five highest consecutive full years of employment during the ten full years of employment immediately preceding the year of calculation. The annual benefit is paid on a monthly basis for 15 years to each participating employee and, if deceased, to the employee's designated beneficiary or estate, commencing at the earliest of death or when the employee is both retired and

62 years of age or more. A participant with vested benefits who is 55 years of age or older and no longer an employee of the Company may elect to be paid benefits beginning at age 55 or older, subject to a discount of such benefits according to the following schedule.

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

2007 Pension Equalization Plan. As discussed above, the 2007 Pension Equalization Plan was eliminated effective January 1, 2010. The annual benefit was 2 percent of the employee's average earnings multiplied by the participant's years of service as an officer (up to a maximum of 15 years) and the vesting percentage. Messrs. Cleberg and Evans were participants in the 2007 Pension Equalization Plan.

Pension Restoration Benefit. In the event that at the time of a participant's retirement, the participant's salary level exceeds the qualified pension plan annual compensation limitation ($245,000 in 2010) or includes nonqualified deferred compensation, then the participant shall receive an additional benefit, called a "Pension Restoration Benefit," which is measured by the difference between (i) the monthly benefit which would have been provided to the participant under the Pension Plan as if there were no annual compensation limitation and no exclusion on nonqualified deferred compensation, and (ii) the monthly benefit to be provided to the participant under the Pension Plan. The Pension Restoration Benefit applies to all of the Named Executive Officers that have a Pension Benefit.

NONQUALIFIED DEFERRED COMPENSATION FOR 2010

We have a Nonqualified Deferred Compensation Plan for a select group of management or highly compensated employees. Eligibility to participate in the plan is determined by the Compensation Committee and primarily consists of only corporate officers.

A summary of the activity in the plan and the aggregate balance as of December 31, 2010 for our Named Executive Officers is shown in the following table. Our Named Executive Officers received no withdrawals or distributions from the plan in 2010.

Name	Executive Contributions in Last Fiscal Year (1)	Company Contributions in Last Fiscal Year (2)	Aggregate Earnings in Last Fiscal Year (3)	Aggregate Balance at Last Fiscal Year End (4)
David R. Emery	—	—	—	—
Anthony S. Cleberg	—	$100,347	$ 2,308	$ 102,655
Linden R. Evans	—	$ 96,925	$ 2,229	$ 99,154
Thomas M. Ohlmacher(5)	$88,443	—	$56,189	$1,293,241
Steven J. Helmers	—	$ 31,935	$ 734	$ 32,669

(1) Mr. Ohlmacher's contributions of $88,443 are included in the Salary column of the Summary Compensation Table.

(2) The Company's contributions represent non-elective Supplemental Matching and Retirement Contributions and Supplemental Target Contributions (defined in the paragraph below) and are included in the Other Compensation column of the Summary Compensation Table.

(3) Mr. Ohlmacher's earnings include $6,684 for dividend equivalents earned on unvested restricted stock units that is included in the All Other Compensation column of the Summary Compensation Table.

(4) Messrs. Cleberg's, Evans' and Helmers' aggregate balance at December 31, 2010 includes $100,347, $96,925 and $31,935, respectively, which are included in the Summary Compensation Table as 2010 Other Compensation.

(5) Mr. Ohlmacher's aggregate balance at December 31, 2010 includes $95,127 and $252,529 which are also included in the Summary Compensation Table as 2010 and 2009 compensation, respectively. The balance does not include any amounts that were reported in the Summary Compensation Table as 2008 compensation.

Eligible employees may elect to defer up to 50 percent of their base salary up to 100 percent of their Short-Term Incentive Plan award, including Company stock, and elect to defer restricted stock grants in the form of restricted stock units. In addition, the Nonqualified Deferred Compensation Plan was amended effective January 1, 2010 to provide certain officers whose Pension Plan benefit and Nonqualified Pension Plans' benefits were frozen effective December 31, 2009, with non-elective supplemental matching contributions equal to 6 percent of eligible compensation in excess of the Internal Revenue Code limit plus matching contributions, if any, lost under the 401(k) Retirement Savings Plan due to nondiscrimination test results and provides non-elective supplemental age and service points-based contributions that cannot be made to the 401(k) Retirement Savings Plan due to the Internal Revenue Code limit ("Supplemental Matching and Retirement Contributions"). It also provides supplemental target contributions equal to a percentage of compensation that may differ by executive, based on the executive's current age and length of service with the Company, as determined by the plans' actuary ("Supplemental Target Contributions"). Messrs. Cleberg, Evans and Helmers received Supplemental Target Contributions of 21.5 percent, 20.0 percent and 7.0 percent, respectively.

The deferrals are deposited into a trust account where the participants may direct the investment of the deferrals (except for Company stock and restricted stock unit deferrals) as allowed by the plan. The investment options are the same as those offered to all employees in the 401(k) Retirement Savings Plan except for a fixed rate option which was set at 4.91 percent in 2010. Investment earnings are credited to the participants' accounts. Upon retirement, we will distribute the account balance to the participant according to the distribution election filed with the Compensation Committee. The participants may elect either a lump sum payment to be paid within 30 days of retirement (requires a six month deferral for benefits not vested as of December 31, 2004), or annual or monthly installments over a period of years designated by the participant, but not to exceed 15 years.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The following table describes the potential payments and benefits under our compensation and benefit plans and arrangements to which our Named Executive Officers would be entitled upon termination of employment. Except for (i) certain terminations following a change in control ("CIC") of the Company, as described below, (ii) pro-rata payout of incentive compensation and the acceleration of vesting of equity awards upon retirement, death or disability, and (iii) certain pension and nonqualified deferred compensation arrangements described under Pension Benefits for 2010 and Nonqualified Deferred Compensation for 2010 above, there are no agreements, arrangements or plans that entitle the Named Executive Officers to severance, perquisites, or other enhanced benefits upon termination of their employment. In addition, we have entered into a consulting agreement with Mr. Ohlmacher to advise us on certain matters after his retirement from the Company. See page 48 for a description of this consulting agreement. Any agreements to provide other payments or benefits to a terminating executive officer would be in the discretion of the Compensation Committee.

The amounts shown below assume that such termination was effective as of December 31, 2010, and thus include estimates of the amounts which would be paid out to our Named Executive Officers upon their termination. The table does not include amounts such as base salary, short-term incentives and stock awards which the Named Executive Officers earned due to employment through December 31, 2010 and distributions of vested benefits such as those described under Pension Benefits for 2010, Nonqualified Deferred Compensation for 2010 and vested stock options listed in the Outstanding Equity Awards at Fiscal Year-End 2010 tables. The table also does not include a value for outplacement services because this would be a de minimis amount. The actual amounts to be paid out can only be determined at the time of such Named Executive Officer's separation from the Company.

	Cash Severance Payment	Incremental Retirement Benefit (present value)(2)	Continuation of Medical/ Welfare Benefits (present value)(3)	Acceleration of Equity Awards(4)	Total Termination Benefits
David R. Emery					
• Retirement	—	—	—	$ 329,578	$ 329,578
• Death or disability	—	—	—	$1,070,218	$1,070,218
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$1,099,651	$1,099,651
• Involuntary or good reason termination after CIC(1)	$3,049,800	$320,300	$172,300	$1,099,651	$4,642,051
Anthony S. Cleberg					
• Retirement	—	—	—	$ 156,942	$ 156,942
• Death or disability	—	—	—	$ 507,762	$ 507,762
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$ 521,781	$ 521,781
• Involuntary or good reason termination after CIC(1)	$ 942,500	$454,118	$ 30,000	$ 521,781	$1,948,399
Linden R. Evans					
• Retirement	—	—	—	$ 198,799	$ 198,799
• Death or disability	—	—	—	$ 630,619	$ 630,619
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$ 648,368	$ 648,368
• Involuntary or good reason termination after CIC(1)	$1,080,000	$412,354	$109,700	$ 648,368	$2,250,422
Thomas M. Ohlmacher					
• Retirement	—	—	—	$ 198,799	$ 198,799
• Death or disability	—	—	—	$ 624,649	$ 624,649
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$ 642,398	$ 642,398
• Involuntary or good reason termination after CIC(1)	$1,065,000	$196,800	$ 28,100	$ 642,398	$1,932,298
Steven J. Helmers					
• Retirement	—	—	—	$ 136,016	$ 136,016
• Death or disability	—	—	—	$ 430,346	$ 430,346
• Involuntary termination	—	—	—	—	—
• CIC	—	—	—	$ 442,494	$ 442,494
• Involuntary or good reason termination after CIC(1)	$ 784,000	$181,113	$ 48,400	$ 442,494	$1,456,007

(1) The amounts reflected for involuntary or good reason termination after a change in control include the benefits a Named Executive Officer would receive in the event of a change in control as a sole event without the involuntary or good reason termination.

(2) Assumes that in the event of a change in control, Mr. Emery will receive an additional three years of credited and vesting service and the other Named Executive Officers will receive an additional two years of credited and vesting service towards the benefit accrual under their applicable retirement plans. For Messrs. Emery and Ohlmacher this would be the Pension Plan and Nonqualified Pension Plans. For Messrs. Cleberg, Evans and Helmers this would be the Retirement Contributions and Nonqualified Deferred Compensation contributions. The benefits will immediately vest and payments will commence at the earliest eligible date unless the executive has elected a later date for the nonqualified plans. This is age 55 for Messrs. Emery, Evans and Helmers. Because Messrs. Cleberg and Ohlmacher are ages 58 and 59, respectively, they are already retiree eligible. In addition, Mr. Ohlmacher has made an election for his Pension Restoration benefit to begin on July 1, 2011 and his Pension Equalization Plan benefit to begin October 1, 2013.

(3) Welfare benefits include medical coverage, dental coverage, life insurance, short-term disability coverage and long-term disability coverage. The calculation assumes that the Named Executive Officer does not take employment with another employer following termination, elects continued welfare benefits until age 55 or, if later, the end of the two year benefit continuation period (three years for Mr. Emery) and elects retiree medical benefits thereafter. Retirement is assumed to occur at the earliest eligible date. Mr. Ohlmacher is already eligible for retiree medical, therefore the only incremental value for retiree medical benefits in his results is the additional two years of employer credits to his retiree medical savings account.

(4) In the event of retirement, death or disability, the acceleration of equity awards represents the acceleration of unvested restricted stock and the assumed payout of the pro-rata share of the performance shares for the January 1, 2009 to December 31, 2011 and January 1, 2010 to December 31, 2012 performance periods. We assumed a 76 percent payout of the performance shares for the January 1, 2009 to December 31, 2011 performance period and a 96 percent payout of target for the January 1, 2010 to December 31, 2012 performance period based on our Monte Carlo valuations at December 31, 2010. In the event of retirement, all unvested restricted stock is forfeited.

In the event of a change in control or an involuntary or good reason termination after a change in control, the acceleration of equity awards represents the acceleration of unvested restricted stock, the payout of the pro-rata share of the performance shares calculated as if the performance period ended on December 31, 2010 for the January 1, 2009 to December 31, 2011 and January 1, 2010 to December 31, 2012 performance periods.

The valuation of the restricted stock was based upon the closing price of our common stock on December 31, 2010 and the valuation of the performance shares was based on the average closing price of our common stock for the last 20 trading days of 2010. Actual amounts to be paid out at the time of separation from the Company may vary significantly based upon the market value of our common stock at that time.

Payments Made Upon Termination. Regardless of the manner in which a Named Executive Officer's employment terminates, he may be entitled to receive amounts earned during his term of employment. These include:

- accrued salary and unused vacation pay;
- amounts vested under the Pension Plan and Nonqualified Pension Plans;
- amounts vested under the Nonqualified Deferred Compensation Plan; and
- amounts vested under the 401(k) Retirement Savings Plan.

Payments Made Upon Retirement: In the event of retirement of a Named Executive Officer, in addition to the items identified above, he will also receive the benefit of the following:

- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon Death or Disability. In the event of death or disability of a Named Executive Officer, in addition to the items identified above, he will also receive the benefit of the following:

- accelerated vesting of restricted stock and restricted stock units;
- a pro-rata share of the performance shares for each outstanding performance period upon completion of the performance period; and
- a pro-rata share of the Short-Term Incentive Plan upon completion of the incentive period.

Payments Made Upon a Change in Control. Our Named Executive Officers have change in control agreements that terminate November 15, 2013. The renewal of the change in control agreements is at the discretion of the Compensation Committee and the Board of Directors. The change in control agreements provide for certain payments and other benefits to be payable upon a change in control and a subsequent termination of employment, either involuntary or for a good reason.

A change in control is defined in the agreements as:

- an acquisition of 30 percent or more of our common stock, except for certain defined acquisitions, such as acquisition by employee benefit plans, us, any of our subsidiaries, or acquisition by an underwriter holding the securities in connection with a public offering thereof; or
- members of our incumbent Board of Directors cease to constitute at least two-thirds of the members of the Board of Directors, with the incumbent Board of Directors being defined as those individuals consisting of the Board of Directors on the date the agreement was executed and any other directors elected subsequently whose election was approved by the incumbent Board of Directors; or
- approval by our shareholders of:
  - a merger, consolidation, or reorganization;
  - liquidation or dissolution; or
  - an agreement for sale or other disposition of 50 percent or more of our assets, with exceptions for transactions which do not involve an effective change in control of voting securities or Board of Directors membership, and transfers to subsidiaries or sale of subsidiaries; and
- all regulatory approvals required to effect a change in control have been obtained and the transaction constituting the change in control has been consummated.

In the change in control agreements, a good reason for termination which would trigger payment of benefits is defined to include:

- a material reduction of the executive's authority, duties or responsibilities;
- a reduction in the executive's annual compensation or any failure to pay the executive any compensation or benefits to which he or she is entitled within seven days of the date due;
- any material breach by us of any provisions of the change in control agreement;

- requiring the executive to be based outside a 50-mile radius from his or her usual and normal place of work; or
- our failure to obtain an agreement, satisfactory to the executive, from any successor company to assume and agree to perform the change in control agreement.

Upon a change in control, the CEO will have an employment contract for a three-year period and the non-CEO executive will have an employment contract for a two-year period, but not beyond age 65 ("employment term"). During this employment term, the executive shall receive annual compensation at least equal to the highest rate in effect at any time during the one-year period preceding the change in control and shall also receive employment welfare benefits, pension benefits, and supplemental retirement benefits on a basis no less favorable than those received prior to the change in control. Annual compensation is defined to include amounts which are includable in the gross income of the executive for federal income tax purposes, including base salary, targeted short-term incentive, targeted long-term incentive grants and awards; and matching contributions or other benefits payable under the 401(k) Retirement Savings Plan; but exclude restricted stock awards, performance units or stock options that become vested or exercisable pursuant to a change in control.

If a Named Executive Officer's employment is terminated prior to the end of the employment term by the Company for cause or disability, by reason of the Named Executive Officer's death, or by the Named Executive Officer without good reason, the Named Executive Officer will receive all amounts of compensation earned or accrued through the termination date. If the Named Executive Officer's employment is terminated because of death or disability, the Named Executive Officer or his beneficiaries will also receive a pro rata bonus equal to 100 percent of the target incentive for the portion of the year served.

If the CEO's employment is terminated during the employment term (other than by reason of death) (i) by the Company other than for cause or disability, or (ii) by the CEO for a good reason, then the CEO is entitled to the following benefits:

- all accrued compensation and a pro rata bonus (the same as the CEO or the CEO's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to 2.99 times the CEO's severance compensation defined as the CEO's base salary and short-term incentive target on the date of the change in control; provided that if the CEO has attained the age of 62 on the termination date, the severance payment shall be adjusted for the ratio of the number of days remaining to the CEO's 65th birthday to 1,095 days;
- continuation of employee welfare benefits for three years following the termination date unless the CEO becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of the CEO or the CEO's eligible dependents;
- following the three-year period, the CEO may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at the CEO's election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- three additional years of service and age will be credited to the CEO's retiree medical savings account and the account balance will become fully vested and he is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the three year continuation period;
- three years of additional credited service under the 2005 Pension Equalization Plan, Pension Restoration Plan and Defined Benefit Pension Plan; and
- outplacement assistance services for up to six months.

If the non-CEO executive's employment is terminated during the employment term (other than by death) (i) by the Company other than for cause or disability, or (ii) by the non-CEO for a good reason; then the non-CEO is entitled to the following benefits:

- all accrued compensation and a pro rata bonus (the same as the non-CEO or the non-CEO's beneficiaries would receive in the event of death or disability discussed above);
- severance pay equal to two times the non-CEO's severance compensation defined as the non-CEO's base salary and short-term incentive target on the date of the change in control; provided that if the non-CEO has attained the age of 63 on the termination date, the severance payment shall be adjusted for the ratio of the number of days remaining to the non-CEO's 65th birthday to 730 days;
- continuation of employee welfare benefits for two years following the termination date unless the non-CEO becomes covered under the health insurance coverage of a subsequent employer which does not contain any exclusion or limitation with respect to any preexisting condition of the non-CEO or the non-CEO's eligible dependents;
- following the two-year period, the non-CEO may elect to receive coverage under the employee welfare plans of the successor entity at his then-current level of benefits (or reduced coverage at the non-CEO's election) by paying the premiums charged to regular full-time employees for such coverage, and is eligible to continue receiving such coverage through the date of his retirement;
- two additional years of service and age will be credited to the non-CEO's retiree medical savings account and the account balance will become fully vested and the non-CEO is eligible to use the account balance to offset retiree medical premiums at the later of age 55 or the end of the two year continuation period;
- two years of additional credited service under the executives applicable retirement plans; and
- outplacement assistance services for up to six months.

The change in control agreements do not contain a benefit to cover any excise tax imposed by Section 4999 of the Internal Revenue Code of 1986. The executive must sign a waiver and release agreement in order to receive the severance payment.

CONSULTING AGREEMENT

On December 1, 2010, we entered into a Consulting Services Agreement (the "Agreement") with Mr. Ohlmacher and T.O.P., LLC ("T.O.P."). Mr. Ohlmacher is the managing member of T.O.P. and previously announced his plans to retire from the Company on March 31, 2011. The Agreement provides that from the date of his retirement until September 30, 2012 we will engage T.O.P. as an independent contractor and consultant, to advise us on strategic, project development and operating matters related to our regulated and non-regulated business activities. In compensation for services, including non-competition, avoidance of conflict and confidentiality, we will pay T.O.P. $143,750 on January 15, 2012 and $143,750 on September 30, 2012.

Proposal 3

ADVISORY VOTE ON OUR EXECUTIVE COMPENSATION

The Company is providing shareholders with an advisory, non-binding vote on the executive compensation of our Named Executive Officers (commonly referred to as "say on pay"). Accordingly shareholders will vote on approval of the following resolution:

> RESOLVED, that the shareholders approve, on an advisory basis, the compensation of our Named Executive Officers as disclosed in the Compensation Discussion and Analysis section, the accompanying compensation tables and the related narrative disclosure in this Proxy Statement.

This vote is non-binding. The Board of Directors and the Compensation Committee expect to take the outcome of the vote into account when considering future executive compensation decisions to the extent they can determine the cause or causes of any significant negative voting results.

As described at length in the Compensation Discussion and Analysis section of this Proxy Statement, we believe our executive compensation program is reasonable, competitive and strongly focused on pay for performance. The compensation of our Named Executive Officers varies depending upon the achievement of pre-established performance goals, both individual and corporate. Our short-term incentive is tied to earnings per share targets that reward our executives when they deliver targeted financial results. Our long-term incentives are tied to market performance with 50 percent delivered in restricted stock and 50 percent delivered in performance shares. Entitlement to the performance shares is based on our total shareholder return over a three-year performance period compared to our peer group. Through stock ownership guidelines, equity incentives and clawback provisions, we align the interests of our executives with those of our shareholders and the long-term interests of the Company. Our executive compensation policies have enabled us to attract and retain talented and experienced senior executives who can drive financial and strategic growth objectives that are intended to enhance shareholder value. We believe that the 2010 compensation of our Named Executive Officers was appropriate and aligned with our 2010 results and position for long-term growth.

Shareholders are encouraged to read the Compensation Discussion and Analysis, the accompanying compensation tables, and the related narrative disclosures to better understand the compensation of our Named Executive Officers.

The Board of Directors recommends a vote *FOR* the advisory vote on executive compensation.

Proposal 4

ADVISORY VOTE ON THE FREQUENCY OF THE ADVISORY VOTE ON OUR EXECUTIVE COMPENSATION

The Company is required to seek an advisory, non-binding shareholder vote on the frequency of submission to shareholders of the advisory vote on executive compensation once every year, every two years or every three years.

This vote is non-binding. The Board will review the voting results and expects to take the outcome of the vote into account when selecting the frequency of advisory votes on executive compensation.

The Board of Directors recognizes the importance of receiving regular input from our shareholders on important issues such as executive compensation. Accordingly, the Board is recommending that shareholders vote for the option of every year as the frequency with which shareholders will have a "say on pay". The Board believes that an annual advisory vote on executive compensation is consistent with the Company's policy of seeking input from, and engaging in discussions with, our shareholders on corporate governance matters. The Board understands that thoughtful analysis of executive compensation can be time consuming for shareholders and that it may be difficult to assess the impact of any changes to our compensation practices within a one-year period. Accordingly, the Board understands that shareholders may have different views on the appropriate frequency for the "say on pay" vote and looks forward to receiving input on this matter.

Although the Board is recommending shareholders vote for the option of every year, for purposes of this proposal, shareholders are entitled to vote for any of the frequency alternatives and you are not voting on the Board's recommendation. The Company will report its determination about the frequency of the advisory vote on executive compensation in a Form 8-K or amendment to a Form 8-K filed within 150 days following the meeting.

The Board of Directors recommends a vote for the option of *ONE YEAR* as the frequency with which shareholders will have an advisory, non-binding vote on executive compensation.

TRANSACTION OF OTHER BUSINESS

Our Board of Directors does not intend to present any business for action by our shareholders at the meeting except the matters referred to in this proxy statement. If any other matters should be properly presented at the meeting, it is the intention of the persons named in the accompanying form of proxy to vote thereon in accordance with the recommendations of our Board of Directors.

SHAREHOLDER PROPOSALS FOR 2012 ANNUAL MEETING

Shareholder proposals intended to be presented at our 2012 annual meeting of shareholders and considered for inclusion in our proxy materials must be received by our Corporate Secretary in writing at our executive offices at 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57709, on or prior to December 15, 2011. Any proposal submitted must be in compliance with Rule 14a-8 of Regulation 14A of the Securities and Exchange Commission.

Additionally, a shareholder may submit a proposal for consideration at our 2012 annual meeting of shareholders, but not for inclusion of the proposal in our proxy materials, if the shareholder gives timely written notice of such proposal in accordance with Article I, Section 9 of our Bylaws. In general, Article I, Section 9 provides that, to be timely, a shareholder's notice must be delivered to our Corporate Secretary in writing not less than 90 days nor more than 120 days prior to the anniversary date of the immediately preceding annual meeting of shareholders.

Our 2011 annual meeting is scheduled for May 25, 2011. Ninety days prior to the first anniversary of this date will be February 25, 2012, and 120 days prior to the first anniversary of this date will be January 26, 2012. For business to be properly requested by the shareholder to be brought before the 2012 annual meeting of shareholders, the shareholder must comply with all of the requirements of Article I, Section 9 of our Bylaws, not just the timeliness requirements set forth above.

SHARED ADDRESS SHAREHOLDERS

In accordance with a notice sent to eligible shareholders who share a single address, we are sending only one annual report and proxy statement to that address unless we receive instructions to the contrary from any shareholder at that address. This practice, known as "householding," is designed to reduce our printing and postage costs. However, if a shareholder of record residing at such an address wishes to receive a separate annual report or proxy statement in the future, he or she may contact Shareholder Relations at the below address. Eligible shareholders of record receiving multiple copies of our annual report and proxy statement can request householding by contacting us in the same manner. Shareholders who own shares through a bank, broker or other nominee can request householding by contacting the nominee.

We hereby undertake to deliver promptly, upon written or oral request, a separate copy of the annual report to shareholders, or proxy statement, as applicable, to our shareholders at a shared address to which a single copy of the document was delivered.

Shareholder Relations
Black Hills Corporation
P.O. Box 1400
Rapid City, SD 57709
(605) 721-1700

Please vote your shares by telephone, by the Internet or by promptly returning the accompanying form of proxy, whether or not you expect to be present at the meeting.

ANNUAL REPORT ON FORM 10-K

A copy of our Annual Report on Form 10-K (excluding exhibits), for the year ended December 31, 2010, which is required to be filed with the Securities and Exchange Commission, will be made available to shareholders to whom this Proxy Statement is mailed, without charge, upon written or oral request to Shareholder Relations, Black Hills Corporation, P.O. Box 1400, Rapid City, SD 57709, Telephone Number: (605) 721-1700. Our Annual Report on Form 10-K also may be accessed through our website at www.blackhillscorp.com.

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD ON MAY 25, 2011

Shareholders may view this proxy statement, our form of proxy and our 2010 Annual Report to Shareholders over the Internet by accessing our website at www.blackhillscorp.com. Information on our website does not constitute a part of this proxy statement.

By Order of the Board of Directors,

Roxann R. Basham

ROXANN R. BASHAM
Vice President—Governance and Corporate Secretary

Dated: April 13, 2011

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BLACK HILLS CORPORATION
P.O. BOX 1400 625 NINTH STREET
RAPID CITY, SOUTH DAKOTA 57709
Fax #(605) 721-2550
e-mail roxann.basham@blackhillscorp.com

ROXANN R. BASHAM
VICE PRESIDENT –
GOVERNANCE AND
CORPORATE SECRETARY

TELEPHONE
(605) 721-2343

April 13, 2011

Federal Express

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

SEC MAIL PROCESSING
RECEIVED
APR 13 2011
WASH, D.C.
211
SECTION

Re: Black Hills Corporations
Annual Report to Shareholders

Ladies and Gentlemen,

We are transmitting herewith for filing with your office, pursuant to Rule 14a-3 under the Securities Exchange Act of 1934, as amended, seven copies of our Annual Report to Shareholders. The Annual Report is solely for the Commission's information and not to be deemed "filed." The Annual Report is being mailed to shareholders on or about April 13, 2011.

Please file-stamp the enclosed copy of this letter and return it to me in the envelope provided.

Sincerely,

Roxann R. Basham

Roxann R. Basham

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

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________________ to ________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota

625 Ninth Street
Rapid City, South Dakota 57701

IRS Identification Number 46-0458824

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

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

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

FORM 10K

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

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

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes ☒ No ☐

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

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

At June 30, 2010 $1,102,103,935

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, 2011
Common stock, $1.00 par value	39,262,118 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2011 Annual Meeting of Stockholders to be held on May 25, 2011, are incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

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
Annexation Agreement	Agreement with the City of Pueblo, Colorado under which the City of Pueblo annexed the property on which Colorado Electric and Black Hills Colorado IPP are constructing their generation facilities
AOCI	Accumulated Other Comprehensive Income
Aquila	Aquila, Inc.
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila
ARO	Asset Retirement Obligations
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
BHC	Black Hills Corporation; the Company
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
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
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., and its subsidiaries
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 Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
CAMR	Clean Air Mercury Rule
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
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
City of Gillette	The City of Gillette, Wyoming, affiliate of the JPB. The JPB financed the purchase of 23% of Wygen III power plant for the City of Gillette
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
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
CPUC	Colorado Public Utilities Commission

CT	Combustion turbine
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under the accounting for derivatives and hedges but subsequently de-designated in December 2008
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
Dth	Dekatherms
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	EDF Trading North America, LLC
Enserco	Enserco Energy Inc., a wholly-owned subsidiary of Black Hills Non-regulated Holdings
Enserco Credit Facility	The $250 million committed stand alone credit facility that supports Enserco's marketing and trading operations, which currently expires May 7, 2012
EPA	U. S. Environmental Protection Agency
Equity forward shares	Public offering of 4,000,000 shares of Black Hills Corporation common stock connected with an Equity Forward Agreement
ERISA	Employee Retirement Income Security Act
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Forward Agreement	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,000,000 million shares of Black Hills Corporation common stock
Forward Agreements	Equity Forward Agreement with J. P. Morgan connected to a public offering of 4,413,519 million shares of Black Hills Corporation common stock, including the over-allotment shares
FTC	Federal Trade Commission
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment
GHG	Greenhouse gases
GIS	Geographic information system
Global Settlement	Settlement with the utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
GSRS	Gas System Reliability Surcharge
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Hastings	Hastings Fund Management Ltd
ICE	Intercontinental Exchange
IGCC	Integrated Gasification Combined Cycle
IIF	IIF BH Investment LLC, a subsidiary of an investment entity advised by JPMorgan Asset Management
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
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
J.P. Morgan	J.P. Morgan Securities LLC
JPB	Consolidated Wyoming Municipalities Electric Power System Joint Powers Board. The JPB exists for the purpose of, among other things, financing the electrical system of the City of Gillette.

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
KCC	Kansas Corporation Commission
kV	Kilovolt
KW	Kilowatt
KWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
MACT	Maximum Achievable Control Technology
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 regulated 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.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
Native load	Energy required to serve customers within our service territory
NCREIF	National Council of Real Estate Investment Fiduciaries
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
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxide
NOL	Net operating loss
NPA	Nebraska Power Association
NPDES	National Pollutant Discharge Elimination System
NPSC	Nebraska Public Service Commission
NQDC	Non-Qualified Deferred Compensation Plan
NYMEX	New York Mercantile Exchange
OCA	Office of Consumer Advocate
OPEC	Organization of the Petroleum Exporting Countries
PCA	Power Cost Adjustment
PGA	Purchased Gas Adjustment
PPA	Purchase Power Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCo	Public Service Company of Colorado
PUD	Proved undeveloped reserves
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
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, issuance of letters of credit and other corporate purposes, expiring April 14, 2013.
RMSA	Retiree Medical Savings Account

SCADA	Supervisory Control and Data Acquisition
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
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
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

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ACCOUNTING PRONOUNCEMENTS

ASC	Accounting Standards Codification
ASC 310-10-50	ASC 310-10-50, "Receivables - Disclosures"
ASC 715	ASC 715, "Compensation - Retirement Benefits"
ASC 805	ASC 805, "Business Combinations"
ASC 810	ASC 810, "Consolidations"
ASC 810-10-15	ASC 810-10-15, "Consolidation of Variable Interest Entities"
ASC 815	ASC 815, "Derivatives and Hedging"
ASC 820	ASC 820, "Fair Value Measurements and Disclosures"
ASC 932-10-S99	ASC 932-10-S99, "Extractive Activities - Oil and Gas, SEC Materials"
ASC 940-325-S99	ASC 940-325-S99, "Financial Services - Broker and Dealers, Investments - Other"

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 Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

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. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. 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. Whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including without limitation, the Risk Factors set forth in Item 1A of this Form 10-K and the other reports we file with the SEC from time to time, and the following:

- Macro- and micro-economic changes in the economy and energy industry, including the impact of (i) consolidations and changes in competition, and (ii) general economic and political conditions, including tax rates or policies and inflation rates;
- 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 comply, or to make expenditures required to comply, with changes in laws and regulations, particularly those relating to energy markets, taxation, safety and protection of the environment, and our ability to recover those expenditures in customer rates, where applicable;
- Federal and state laws concerning climate change and air emissions, including emission reduction mandates, carbon emissions and renewable energy portfolio standards, which may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain, or which could require closure of one or more of our generating units;
- Changes in business, regulatory compliance and financial reporting practices arising from the enactment of the Energy Policy Act of 2005 and subsequent rules and regulations promulgated thereunder;
- The effect of Dodd-Frank and the regulations to be adopted thereunder on our use of derivative instruments in connection with our energy marketing activities and to hedge our expected production of oil and natural gas and on our use of interest rate derivative instruments;
- Changes in state laws or regulations that could cause us to curtail our independent power production or exploration and production activities;
- Our ability to successfully integrate and profitably operate any future acquisitions;
- 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, transportation, transmission and purchased power in our regulated utilities;
- Our ability to receive regulatory approval to recover in rate base our expenditures for new power generation facilities or other utility infrastructure;
- Our ability to recover our borrowing costs, including debt service costs, in our customer rates;
- The extent of our success in connecting natural gas supplies to gathering, processing and pipeline systems;
- Our ability to minimize losses related to defaults on amounts due from customers and counterparties, including counterparties to trading and other commercial transactions;

- The timing and extent of scheduled and unscheduled outages of power generation facilities;
- Our ability to complete the permitting, construction, start-up and operation of power generating facilities in a cost-effective and timely manner;
- Our ability to accurately estimate demand from our customers for natural gas;
- Weather and other natural phenomena;
- Our ability to meet forecasted production volumes 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;
- The amount of collateral required to be posted from time to time in our transactions;
- Our ability to effectively use derivative financial instruments to hedge commodity, currency exchange rate and interest rate risks;
- Our ability to provide accurate estimates of proved oil and gas reserves, coal reserves and future production rates and associated costs;
- Price risk due to marketable securities held as investments in employee benefit plans;
- Our ability to successfully maintain our corporate credit rating;
- Our ability to access revolving credit capacity and comply with loan covenants;
- Capital market conditions and market uncertainties related to interest rates, which may affect our ability to raise capital on favorable terms;
- The amount and timing of capital deployment in new investment opportunities or for the repurchase of debt or stock;
- Our ability to continue paying our regular quarterly dividend;
- Our ability to obtain permanent financing for capital expenditures on reasonable terms either through long-term debt or issuance of equity;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The accounting treatment and earnings impact associated with interest rate swaps;
- 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;
- 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;
- Additional liabilities for environmental conditions, including remediation and reclamation obligations, under environmental laws;
- Our ability to successfully complete labor negotiations with labor unions with whom we have collective bargaining agreements and for which we are currently in, or are soon to be in, contract renewal negotiations; and
- The cost and effect on our business, including insurance, resulting from terrorist actions or responses to such actions or events.

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 (together with its subsidiaries, referred to herein as the "Company," "we," "us" and "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 producing, selling and marketing various forms of energy through its non-regulated business.

We operate principally in the United States with two major business groups: Utilities and Non-regulated Energy. Our Utilities Group is comprised of our regulated Electric Utilities and regulated 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, 2010, we had 2,124 employees, 705 of whom 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

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Our Electric Utilities segment generates, transmits and distributes electricity to approximately 201,000 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light, a combination electric and gas utility, and its approximately 34,500 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 527,000 natural gas utility customers in Colorado, Nebraska, Iowa and Kansas. Our Electric Utilities own 687 MWs of generation and 8,038 miles of electric transmission and distribution lines, and our Gas Utilities own 626 miles of intrastate gas transmission pipelines and 19,638 miles of gas distribution mains and service lines. Our Electric and Gas Utilities generated income from continuing operations of $74.6 million for the year ended December 31, 2010 and had total assets of $2.6 billion at December 31, 2010.

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 is engaged in marketing of natural gas, crude oil, coal, power, environmental products and related services, in the United 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. Our Non-regulated Energy Group generated income from continuing operations of $13.6 million in the year ended December 31, 2010 and had total assets of $1.1 billion at December 31, 2010.

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 17 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 201,000 customers in South Dakota, Wyoming, Colorado and Montana. Additionally, Cheyenne Light distributes natural gas to approximately 34,500 natural gas utility customers 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 and transport natural gas to our customers through our distribution network to approximately 527,000 customers in Colorado, Iowa, Kansas and Nebraska. We also provide related services that include appliance repairs, gas technical services and the sale of temporarily-available, contractual pipeline capacity from our suppliers.

In addition to our regulated operations, we also provide services through our Service Guard product line to approximately 63,000 customers in Colorado, Iowa, Kansas and Nebraska. Service Guard primarily provides appliance repair services through company technicians and third party service providers.

Electric Utilities Segment

Capacity and Demand

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

	System Peak Demand (in MW)					
	2010		2009		2008	
	Summer	Winter	Summer	Winter	Summer	Winter
Black Hills Power	396	377	387	392	409	407
Cheyenne Light	176	164	169	171	166	168
Colorado Electric	384	289	365	296	306 (a)	298 (a)
Total Electric Utilities Peak Demands	956	830	921	859	881	873

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

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Regulated Power Plants

As of December 31, 2010, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
Black Hills Power:					
Wygen III (1)	Coal	Gillette, WY	52.0 %	57.2	2010
Neil Simpson II	Coal	Gillette, WY	100.0 %	90.0	1995
Wyodak (2)	Coal	Gillette, WY	20.0 %	72.4	1978
Osage (3)	Coal	Osage, WY	100.0 %	34.5	1948-1952
Ben French	Coal	Rapid City, SD	100.0 %	25.0	1960
Neil Simpson I	Coal	Gillette, WY	100.0 %	21.8	1969
Neil Simpson CT	Gas	Gillette, WY	100.0 %	40.0	2000
Lange CT	Gas	Rapid City, SD	100.0 %	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, SD	100.0 %	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, SD	100.0 %	100.0	1977-1979
Cheyenne Light:					
Wygen II	Coal	Gillette, WY	100.0 %	95.0	2008
Colorado Electric (4):					
W.N. Clark #1-2 (5)	Coal	Canon City, CO	100.0 %	42.0	1955, 1959
Pueblo #6	Gas	Pueblo, CO	100.0 %	20.0	1949
Pueblo #5	Gas	Pueblo, CO	100.0 %	9.0	1941, 2001
AIP Diesel	Oil	Pueblo, CO	100.0 %	10.0	2001
Diesel #1-5	Oil	Pueblo, CO	100.0 %	10.0	1964
Diesel #1-5	Oil	Rocky Ford, CO	100.0 %	10.0	1964
Total MW Owned Capacity				686.9	

(1) Construction of Wygen III, a 110 MW mine-mouth coal-fired power plant was completed in April 2010. Black Hills Power operates the plant and owns a 52% interest in the facility, MDU owns a 25% interest and the City of Gillette owns a 23% interest. Our WRDC coal mine furnishes 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% by Black Hills Power. This baseload plant is operated by PacifiCorp and our WRDC coal mine furnishes all of the coal fuel supply for the plant.
(3) Operations at the Osage plant were suspended October 1, 2010 due to the availability of more economical generation alternatives.
(4) The construction of two 90 MW gas-fired power generation facilities is underway to support the customers of Colorado Electric. These facilities are expected to be completed by December 31, 2011.
(5) In December 2010, Colorado Electric received a final order from CPUC which approved the retirement of its W.N. Clark coal-fired generation facility by December 31, 2013 and granted a presumption of need in the amount of 42 MW for replacement of the plant. Colorado Electric will file a Certificate of Public Convenience and Necessity to provide justification for an additional 50 MW of generating capacity to allow the construction of a third 92 MW GE LMS100 natural gas-fired generator at the Pueblo Airport Generation Station where two 90 MW facilities are currently under construction.

The following table shows the Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh (dollars per MWh):

Fuel Source	2010	2009	2008(1)
Coal	$ 12.77	$ 13.99	$ 11.41
Gas and Oil	$ 131.28	$ 85.52	$ 88.60
Total Average Fuel Cost	$ 13.57	$ 15.22	$ 13.18
Purchased Power(2)	$ 30.23	$ 28.93	$ 38.06

(1) 2008 includes Colorado Electric from July 14, 2008 through December 31, 2008.
(2) Includes Happy Jack commencing in October 2008, and Silver Sage commencing in October 2009.

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

Power Supply	2010	2009	2008
Coal-fired	42 %	39 %	44 %
Gas and Oil	—	1	1
Total Generated	42	40	45
Purchased	58	60	55
Total	100 %	100 %	100 %

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

- Black Hills Power's PPA with PacifiCorp expiring in 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Black Hills Power's reserve capacity integration agreement with PacifiCorp expiring in 2012, which makes available 100 MW of reserve capacity in connection with the utilization of the Ben French CT units;
- Colorado Electric's PPA with PSCo expiring at the end of 2011, whereby Colorado Electric purchases a majority of its power. The contract provides for 300 MW of capacity and energy in 2011;
- Colorado Electric's 20-year PPA with Black Hills Colorado IPP, beginning on January 1, 2012 and expiring in 2031, which will provide 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines, which are currently under construction;
- Cheyenne Light's PPA with Black Hills Wyoming expiring in August 2011 whereby Black Hills Wyoming provides 40 MW of energy and capacity from its Gillette CT;
- Cheyenne Light's PPA with Black Hills Wyoming expiring December 31, 2022 whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW which is equivalent to the estimated initial per MW price of new construction of the Wygen III facility. This price is reduced annually by an amount of annual depreciation assuming a facility life of 35 years;
- Cheyenne Light's 20-year PPA with Duke Energy, expiring in 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 50% of the facility's output to Black Hills Power;
- Cheyenne Light and Black Hills Power's Generation Dispatch Agreement requires Black Hills Power to purchase all of Cheyenne Light's excess energy; and
- Cheyenne Light's 20-year PPA with Duke Energy, expiring in 2029, provides 30 MW of wind energy from the Silver Sage wind farm to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 20 MW of energy from Silver Sage to Black Hills Power.

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

- In conjunction with MDU's April 2009 purchase of a 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. The sales to MDU have been integrated into Black Hills Power's control area and are considered part of our firm native load. MWs from the Wygen III unit are deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;
- Black Hills Power's agreement with the City of Gillette to dispatch the City of Gillette's 23% of Wygen III's net generating capacity for the life of the plant. Upon the City of Gillette's July 2010 purchase of a 23% ownership interest in Wygen III, a seven year PPA with the City of Gillette that went into effect in April 2010, was terminated. The City of Gillette's 23 MW of Wygen III capacity has been integrated into Black Hills Power's control area and are considered part of our firm native load. During periods of reduced production at Wygen III, or during periods when Wygen III is

off-line, we will provide the City of Gillette with its first 23 MW from our other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement Black Hills Power will also provide the City of Gillette their operating component of spinning reserves;

- Black Hills Power's agreement to supply 20 MW of energy and capacity to MEAN under a contract that expires in 2023. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2010-2017	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II;

- Black Hills Power's five-year PPA with MEAN which commenced in May 2010 whereby MEAN will purchase 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III; and
- Cheyenne Light's agreement with Basin Electric whereby Cheyenne Light will supply 40 MW of capacity and energy through March 31, 2013 and a separate agreement whereby Cheyenne Light will receive 40 MW of capacity and energy from Basin Electric through March 31, 2013. The agreements become effective on March 14, 2011, and terminate prior agreements under which Cheyenne Light supplies Basin Electric with 80 MW of energy and capacity, and Basin Electric supplies Cheyenne Light with 80 MW of energy and capacity.

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, 2010, our regulated 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	565	2,933
Black Hills Power - Jointly Owned [(1)]	SD, WY	47	—
Cheyenne Light	SD, WY	25	1,176
Colorado Electric	CO	260	3,032

(1) Through Black Hills Power, we own 35% of a DC 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. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. Black Hills Power's electric system is located in the WECC region. 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 power price differentials between the two grids.

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 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 2017, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

Shared Services Agreement. Black Hills Power, Cheyenne Light, and Black Hills Wyoming are parties to a shared facilities agreement whereby each entity charges for the use of assets used by an affiliate entity. This agreement commenced during 2010.

Operating Statistics

The following tables summarize sales revenues, quantities and customers for our Electric Utilities. Amounts shown for 2008 include Colorado Electric from our July 14, 2008 acquisition date through December 31, 2008.

Sales Revenues (in thousands)

	2010	2009	2008
Residential:			
Black Hills Power	$ 53,549	$ 48,586	$ 46,854
Cheyenne Light	29,506	29,198	31,394
Colorado Electric	76,596	66,548	32,620
Total Residential	159,651	144,332	110,868
Commercial:			
Black Hills Power	65,997	59,897	58,289
Cheyenne Light	52,765	51,280	51,609
Colorado Electric	66,490	56,002	28,531
Total Commercial	185,252	167,179	138,429
Industrial:			
Black Hills Power	22,621	20,014	21,432
Cheyenne Light	10,542	11,121	9,716
Colorado Electric	28,812	31,067	16,280
Total Industrial	61,975	62,202	47,428
Municipal:			
Black Hills Power	3,029	2,735	2,734
Cheyenne Light	1,293	932	973
Colorado Electric	10,443	4,408	2,289
Total Municipal	14,765	8,075	5,996
Contract Wholesale:			
Black Hills Power	22,996	25,358	26,643
Off-system Wholesale:			
Black Hills Power	36,354	32,212	63,770
Cheyenne Light	9,750	8,565	6,105
Colorado Electric	10,859	14,008	11,194
Total Off-system Wholesale	56,963	54,785	81,069
Other Sales Revenue:			
Black Hills Power	25,217	18,277	12,950
Cheyenne Light	3,230	718	394
Colorado Electric	2,374	4,226	1,346
Total Other Sales Revenue	30,821	23,221	14,690
Total Sales Revenues	$ 532,423	$ 485,152	$ 425,123

FORM 10K

Quantities Generated and Purchased (MWh)

	2010	2009	2008
Generated -			
Coal-fired:			
Black Hills Power	1,987,037	1,721,074	1,731,838
Cheyenne Light	734,241	766,943	740,051
Colorado Electric	257,896	252,603	138,424
Total Coal	2,979,174	2,740,620	2,610,313
Gas and Oil-fired:			
Black Hills Power	19,269	46,723	61,801
Cheyenne Light	—	—	—
Colorado Electric	930	2,705	306
Total Gas and Oil	20,199	49,428	62,107
Total Generated:			
Black Hills Power	2,006,306	1,767,797	1,793,639
Cheyenne Light	734,241	766,943	740,051
Colorado Electric	258,826	255,308	138,730
Total Generated	2,999,373	2,790,048	2,672,420
Purchased -			
Black Hills Power	1,440,579	1,686,455	1,703,088
Cheyenne Light	696,756	651,201	590,622
Colorado Electric	1,969,896	1,991,058	1,028,029
Total Purchased	4,107,231	4,328,714	3,321,739
Total Generated and Purchased	7,106,604	7,118,762	5,994,159

FORM 10K

Quantity (MWh)

	2010	2009	2008
Residential:			
Black Hills Power	547,193	529,825	524,413
Cheyenne Light	261,607	255,134	255,345
Colorado Electric	628,553	589,526	284,294
Total Residential	1,437,353	1,374,485	1,064,052
Commercial:			
Black Hills Power	720,119	723,360	699,734
Cheyenne Light	603,323	583,986	586,151
Colorado Electric	726,005	666,563	330,870
Total Commercial	2,049,447	1,973,909	1,616,755
Industrial:			
Black Hills Power	382,562	353,041	414,421
Cheyenne Light	161,082	174,792	144,179
Colorado Electric	347,673	452,584	235,218
Total Industrial	891,317	980,417	793,818
Municipal:			
Black Hills Power	33,908	33,948	34,368
Cheyenne Light	6,477	3,456	3,669
Colorado Electric	113,689	37,244	19,740
Total Municipal	154,074	74,648	57,777
Contract Wholesale:			
Black Hills Power	468,782	645,297	665,795
Off-system Wholesale:			
Black Hills Power	1,163,058	1,009,574	1,074,398
Cheyenne Light	311,524	309,122	246,542
Colorado Electric	274,942	373,495	230,333
Total Off-system Wholesale	1,749,524	1,692,191	1,551,273
Total Quantity Sold:			
Black Hills Power	3,315,622	3,295,045	3,413,129
Cheyenne Light	1,344,013	1,326,490	1,235,886
Colorado Electric	2,090,862	2,119,412	1,100,455
Total Quantity Sold	6,750,497	6,740,947	5,749,470
Losses and Company Use:			
Black Hills Power	131,263	159,207	83,598
Cheyenne Light	86,984	91,654	94,787
Colorado Electric	137,860	126,954	66,304
Total Losses and Company Use	356,107	377,815	244,689
Total Energy	7,106,604	7,118,762	5,994,159

FORM 10K

Degree Days

	2010		2009		2008	
	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average	Actual	Variance from 30-Year Average
Heating Degree Days:						
Actual -						
Black Hills Power	7,272	1 %	7,753	8 %	7,676	6 %
Cheyenne Light	7,033	(5)%	7,411	— %	7,435	1 %
Colorado Electric	5,518	(1)%	5,546	(1)%	2,204	(5)%
Cooling Degree Days:						
Actual -						
Black Hills Power	532	(11)%	354	(41)%	482	(19)%
Cheyenne Light	345	26 %	203	(26)%	372	36 %
Colorado Electric	1,074	16 %	804	(13)%	500	(12)%

A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.

A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.

Electric Customers at Year-End	2010	2009	2008
Residential:			
Black Hills Power	54,811	54,470	53,765
Cheyenne Light	34,913	35,943	35,205
Colorado Electric	81,902	81,622	81,561
Total Residential	171,626	172,035	170,531
Commercial:			
Black Hills Power	12,779	12,261	12,213
Cheyenne Light	4,132	4,932	4,563
Colorado Electric	11,185	11,101	11,155
Total Commercial	28,096	28,294	27,931
Industrial:			
Black Hills Power	40	38	40
Cheyenne Light	2	2	2
Colorado Electric	63	90	93
Total Industrial	105	130	135
Contract Wholesale:			
Black Hills Power	3	3	3
Other Electric Customers:			
Black Hills Power	309	143	3,010
Cheyenne Light	254	13	6
Colorado Electric	510	499	480
Total Other Electric Customers	1,073	655	3,496
Total Customers:			
Black Hills Power	67,942	66,915	69,031
Cheyenne Light	39,301	40,890	39,776
Colorado Electric	93,660	93,312	93,289
Total Customers	200,903	201,117	202,096

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Cheyenne Light Natural Gas Distribution

Cheyenne Light's natural gas distribution system serves natural gas customers in Cheyenne and other portions of Laramie County, Wyoming. The following table summarizes certain operating information:

	2010	2009	2008
Sales Revenues (in thousands):			
Residential	$ 22,562	$ 21,495	$ 28,059
Commercial	10,801	9,821	13,751
Industrial	3,425	3,537	5,668
Other Sales Revenues	803	760	818
Total Sales Revenues	$ 37,591	$ 35,613	$ 48,296
Sales Margins (in thousands):			
Residential	$ 10,004	$ 10,219	$ 10,083
Commercial	3,376	3,266	3,177
Industrial	427	509	483
Other Sales Margins	720	760	818
Total Sales Margins	$ 14,527	$ 14,754	$ 14,561
Volumes Sold (Dth):			
Residential	2,636,839	2,516,699	2,582,248
Commercial	1,572,638	1,502,002	1,501,025
Industrial	667,062	722,776	689,945
Total Volumes Sold	4,876,539	4,741,477	4,773,218
Customers	34,461	33,942	33,243

Gas Utilities Segment

At December 31, 2010, our Gas Utilities owned the gas transmission and distribution lines by state shown below (in line miles):

	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Colorado	122	2,967	871
Nebraska	51	3,406	3,462
Iowa	170	2,753	2,313
Kansas	283	2,578	1,288
Total	626	11,704	7,934

Operating Statistics

The following tables summarize revenues, sales margins, volumes, degree days and customers for our Gas Utilities. Amounts shown for 2008 include Gas Utilities from our July 14, 2008 acquisition date through December 31, 2008.

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Revenues (in thousands)	2010	2009	2008
Residential:			
Colorado	$ 55,211	$ 62,732	$ 27,928
Nebraska	120,365	127,120	60,624
Iowa	105,255	113,781	47,338
Kansas	69,859	70,848	31,456
Total Residential	350,690	374,481	167,346
Commercial:			
Colorado	11,880	13,357	6,356
Nebraska	40,720	43,472	20,705
Iowa	46,762	54,587	26,003
Kansas	21,953	22,629	10,092
Total Commercial	121,315	134,045	63,156
Industrial:			
Colorado	1,409	1,348	1,495
Nebraska	3,126	3,425	1,640
Iowa	2,243	2,191	1,581
Kansas	14,312	11,057	14,667
Total Industrial	21,090	18,021	19,383
Other Sales Revenue:			
Colorado	97	100	39
Nebraska	1,960	2,077	907
Iowa	836	1,073	457
Kansas	3,451	3,213	1,600
Total Other Sales Margins	6,344	6,463	3,003
Total Distribution:			
Colorado	68,597	77,537	35,818
Nebraska	166,171	176,094	83,876
Iowa	155,096	171,632	75,379
Kansas	109,575	107,747	57,815
Total Distribution	499,439	533,010	252,888
Transportation:			
Colorado	784	732	278
Nebraska	11,289	10,569	4,703
Iowa	3,708	3,876	1,609
Kansas	5,471	5,389	2,409
Total Transportation	21,252	20,566	8,999
Total Regulated:			
Colorado	69,381	78,269	36,096
Nebraska	177,460	186,663	88,579
Iowa	158,804	175,508	76,988
Kansas	115,046	113,136	60,224
Total Regulated Sales Margins	520,691	553,576	261,887
Non-regulated Services	30,016	26,736	15,189
Total Revenues	$ 550,707	$ 580,312	$ 277,076

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Sales Margins (in thousands)	2010	2009	2008
Residential:			
Colorado	$ 18,153	$ 17,443	$ 5,984
Nebraska	49,074	44,638	19,460
Iowa	44,269	42,734	16,335
Kansas	29,591	28,999	12,436
Total Residential	141,087	133,814	54,215
Commercial:			
Colorado	3,215	3,176	1,131
Nebraska	11,965	11,785	4,952
Iowa	11,616	12,749	5,210
Kansas	6,544	6,484	2,693
Total Commercial	33,340	34,194	13,986
Industrial:			
Colorado	360	375	232
Nebraska	379	431	173
Iowa	235	244	105
Kansas	1,878	1,766	1,041
Total Industrial	2,852	2,816	1,551
Other Sales Margins:			
Colorado	97	101	39
Nebraska	1,960	2,077	907
Iowa	836	1,073	457
Kansas	2,722	2,312	1,177
Total Other Sales Margins	5,615	5,563	2,580
Total Distribution:			
Colorado	21,825	21,095	7,386
Nebraska	63,378	58,931	25,492
Iowa	56,956	56,800	22,107
Kansas	40,735	39,561	17,347
Total Distribution	182,894	176,387	72,332
Transportation:			
Colorado	784	732	278
Nebraska	11,289	10,569	4,703
Iowa	3,708	3,876	1,609
Kansas	5,470	5,389	2,409
Total Transportation	21,251	20,566	8,999
Total Regulated:			
Colorado	22,609	21,827	7,664
Nebraska	74,667	69,500	30,195
Iowa	60,664	60,676	23,716
Kansas	46,205	44,950	19,756
Total Regulated Sales Margins	204,145	196,953	81,331
Non-regulated Services	12,845	11,643	3,895
Total Sales Margins	$ 216,990	$ 208,596	$ 85,226

Volumes (in Dth)	2010	2009	2008
Residential:			
Colorado	6,284,559	6,355,275	2,344,549
Nebraska	12,210,574	12,619,682	5,115,805
Iowa	10,556,045	10,976,268	4,126,150
Kansas	6,926,928	6,878,243	2,682,850
Total Residential	35,978,106	36,829,468	14,269,354
Commercial:			
Colorado	1,473,924	1,444,360	563,169
Nebraska	5,009,105	5,189,630	2,133,433
Iowa	6,061,954	6,597,035	2,749,234
Kansas	2,673,805	2,696,870	1,063,356
Total Commercial	15,218,788	15,927,895	6,509,192
Industrial:			
Colorado	259,985	263,134	164,112
Nebraska	544,457	581,892	248,256
Iowa	354,435	333,324	196,841
Kansas	2,718,767	2,524,126	1,586,306
Total Industrial	3,877,644	3,702,476	2,195,515
Other Volumes:			
Colorado	—	—	—
Nebraska	1,341	1,400	320
Iowa	69,306	68,290	18,301
Kansas	120,445	141,909	60,917
Total Other Volumes	191,092	211,599	79,538
Total Distribution:			
Colorado	8,018,468	8,062,769	3,071,830
Nebraska	17,765,477	18,392,604	7,497,814
Iowa	17,041,740	17,974,917	7,090,526
Kansas	12,439,945	12,241,148	5,393,429
Total Distribution	55,265,630	56,671,438	23,053,599
Transportation:			
Colorado	808,859	807,999	347,822
Nebraska	27,327,173	25,311,501	12,930,165
Iowa	17,422,525	14,915,602	6,312,050
Kansas	14,320,893	14,069,182	7,215,038
Total Transportation	59,879,450	55,104,284	26,805,075
Total Volumes:			
Colorado	8,827,327	8,870,768	3,419,652
Nebraska	45,092,650	43,704,105	20,427,979
Iowa	34,464,265	32,890,519	13,402,576
Kansas	26,760,838	26,310,330	12,608,467
Total Volumes	115,145,080	111,775,722	49,858,674

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Degree Days

	2010		2009		2008	
	Actual	Variance From 30-Year Average	Actual	Variance From 30-Year Average	Actual *	Variance From 30-Year Average *
Heating Degree Days:						
Colorado	5,803	(9)%	6,299	2 %	2,376	(7)%
Nebraska	6,222	(5)%	6,238	5 %	2,458	— %
Iowa	6,934	(1)%	7,279	6 %	2,909	3 %
Kansas	4,918	— %	4,989	— %	1,897	(3)%
Combined	6,101	(3)%	6,285	(11)%	2,471	— %

* Gas Utilities acquired on July 14, 2008.

A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average. For service areas that have weather normalization operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days. The combined heating degree days are calculated based on a weighted average of total customers by state.

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The following table summarizes the Gas Utilities' customers as of December 31:

Customers	2010	2009	2008
Residential:			
Colorado	66,766	65,586	64,601
Nebraska	176,244	179,873	177,432
Iowa	134,782	133,712	133,442
Kansas	97,844	97,446	96,593
Total Residential	475,636	476,617	472,068
Commercial:			
Colorado	3,620	3,590	3,579
Nebraska	15,221	15,218	15,034
Iowa	15,300	15,403	15,467
Kansas	9,469	9,510	9,463
Total Commercial	43,610	43,721	43,543
Industrial:			
Colorado	208	207	208
Nebraska	149	149	149
Iowa	93	90	84
Kansas	1,394	1,351	1,267
Total Industrial	1,844	1,797	1,708
Transportation:			
Colorado	22	22	21
Nebraska	4,270	4,579	4,758
Iowa	392	389	397
Kansas	1,054	1,077	1,174
Total Transportation	5,738	6,067	6,350
Other:			
Colorado	—	—	—
Nebraska	2	2	2
Iowa	68	71	69
Kansas	8	8	8
Total Other	78	81	79
Total Customers:			
Colorado	70,616	69,405	68,409
Nebraska	195,886	199,821	197,375
Iowa	150,635	149,665	149,459
Kansas	109,769	109,392	108,505
Total Customers	526,906	528,283	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 and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand 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 electric utilities. Conversely, for our Gas Utilities, 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 consisting of the first and fourth quarters.

Competition

We face competition from other utilities and non-affiliated IPP companies for the right to provide power and capacity for Colorado Electric. However, 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 several of the states in which our utilities operate, but none of these initiatives have been adopted to date with the exception of Montana. 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 for transporting the gas through our distribution network. In Colorado, our electric utility is subject to rules which require competitive bidding for generation supply.

Regulation and Rates

State Regulation

Our utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. 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. 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, and Cheyenne Light's natural gas distribution, have gas cost adjustments that allow us to pass the prudently-incurred cost of gas through to the customer. In Kansas and Nebraska, we are also allowed to recover the portion of uncollectible accounts related to gas costs through the gas cost adjustments. In Kansas, we have a weather normalization tariff that provides a pass-through mechanism for weather margin variability that occurs from the level used to establish base rates to be paid by the customer. In Kansas, we also have tariffs that provide for more timely recovery for certain capital expenditures and fluctuations in property taxes. In Nebraska, legislation was passed in 2009 to authorize the NPSC to provide for more timely recovery from our customers for certain capital expenditures between rate cases.

We produce and distribute power in four states. The regulatory provisions for recovering the costs to produce electricity vary by state. In South Dakota, Wyoming, Colorado and Montana, 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 above or below the threshold.

Until April 1, 2010 South Dakota had three adjustment mechanisms: transmission, steam plant fuel (coal) and conditional energy cost adjustment. The transmission and steam plant fuel adjustment clauses required an annual adjustment to rates for actual costs, therefore any savings or increased costs were passed on to the South Dakota customers. The conditional energy cost adjustment related to purchased power and natural gas used to generate electricity. These costs were subject to calendar year $2.0 million and $1.0 million thresholds where Black Hills Power absorbed the first $2.0 million of increased costs or retained the first $1.0 million in savings. Beyond these thresholds, costs or savings were passed on to South Dakota customers through annual calendar-year filings.

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In South Dakota beginning April 1, 2010, the steam plant fuel and conditional energy cost adjustment were combined into a single cost adjustment called the Fuel and Purchased Power Adjustment clause. The Fuel and Purchased Power Adjustment Clause provides for the direct recovery of increased fuel and purchased power costs incurred to serve South Dakota customers. As of April 1, 2010, the Fuel and Purchased Power Adjustment clause was modified in the rate case settlement to contain a power marketing operating income sharing mechanism in which South Dakota customers will receive a credit equal to 65% of power marketing operating income. The modification also adjusts the methodology to directly assign renewable resources and firm purchases to the customer load. In Wyoming beginning June 1, 2010 a similar Fuel and Purchase Power Cost Adjustment was instituted.

In Colorado, we have a cost adjustment for increases or decreases in 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 an authorized return on new transmission investment and recovery of operations and maintenance costs related to transmission.

In Colorado, beginning in November 2010, the CPUC approved the implementation of a Purchased Capacity Cost Adjustment, the purpose of which is to recover the increase in capacity cost related to Colorado Electric's purchase power agreement with PSCo.

The above mechanisms allow the utilities to collect, or refund, the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services 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 where 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, 2010, 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. 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. We are currently in compliance with applicable standards.
- Colorado. Colorado has 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) 12% of retail sales from 2011 to 2014 (ii) 20% of retail sales from 2015 to 2019; and (iii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from renewable resources with one-half of the renewable resources being located at customer facilities. The 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. Our current strategy is to incorporate renewable energy as required to comply with the standards.

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 utility 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 of the costs we pay to be in compliance with standards or objectives.

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.

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. Our public utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities and our two of our non-regulated subsidiaries, Black Hills Wyoming and Enserco, 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 provides 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.

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 a utility holding company. As a utility holding company with centralized service company subsidiaries, Black Hills Service Company and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

The following summarizes our recent state and federal rate case and surcharge activity (dollars in millions):

							Approved Capital Structure	
	Type of Service	**Date Requested**	**Date Effective**	**Amount Requested**	**Amount Approved**	**Return on Equity**	**Equity**	**Debt**
Nebraska Gas [1]	Gas	12/2009	9/2010	$ 12.1	$ 8.3	10.1 %	52.0 %	48.0 %
Iowa Gas	Gas	6/2008	7/2009	$ 13.6	$ 10.8	10.1 %	51.4 %	48.6 %
Iowa Gas [2]	Gas	6/2010	2/2011	$ 4.7	$ 3.4	Global Settlement	Global Settlement	Global Settlement
Colorado Gas	Gas	6/2008	4/2009	$ 2.7	$ 1.4	10.3 %	50.5 %	49.5 %
Kansas Gas	Gas	5/2009	10/2009	$ 0.5	$ 0.5	10.2 %	50.7 %	49.3 %
Black Hills Power [3]	Electric	9/2008	1/2009	$ 4.5	$ 3.8	10.8 %	57.0 %	43.0 %
Black Hills Power [4]	Electric	9/2009	4/2010	$ 32.0	$ 15.2	Global Settlement	Global Settlement	Global Settlement
Black Hills Power [5]	Electric	10/2009	6/2010	$ 3.8	$ 3.1	10.5 %	52.0 %	48.0 %
Colorado Electric [6]	Electric	1/2010	8/2010	$ 22.9	$ 17.9	10.5 %	52.0 %	48.0 %

(1) On December 1, 2009, Nebraska Gas filed with the NPSC a $12.1 million rate case requesting a gas revenue increase to recover operating costs and distribution system investments. The proposed increase in revenue was approximately 6.5%. Interim rates, subject to refund for the entire amount of the proposed increase, went into effect on March 1, 2010. On August 18, 2010, NPSC issued a decision approving an annual revenue increase of approximately $8.3 million, based on a return on equity of 10.1% with a capital structure of 52% equity effective September 1, 2010. A plan for refund has been approved by the NPSC. An appeal was filed by the OCA relating to the entire rate case decision. However, the NPSC denied this appeal. Subsequently, the OCA filed an appeal

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in September 2010 appealing a portion of the Commission's order addressing our affiliate transactions. The appeal is still outstanding.

(2) On June 8, 2010, Iowa Gas filed a request with the IUB for a $4.7 million revenue increase to recover the cost of capital investments made in our gas distribution system and other expense increases incurred since December 2008. Interim rates, subject to refund, equal to a $2.6 million increase in revenues went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of $3.4 million. This settlement agreement was modified and re-filed on January 11, 2011. The modified settlement excludes the integrity investment tracker and the three-year rate moratorium included in the original settlement agreement filed on September 1, 2010, which was not approved by the IUB. Approval from the IUB was received on February 10, 2011.

(3) On February 10, 2009, FERC approved a formulaic approach to the method used to determine the revenue component of Black Hills Power's open access transmission tariff, and increased the utility's annual transmission revenue requirement by approximately $3.8 million. The revenue requirement is based on an equity return of 10.8%, and a capital structure consisting of 57% equity and 43% debt. New annual rates went into effect on January 1, 2009.

(4) On September 30, 2009, Black Hills Power filed a rate case with the SDPUC requesting an electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred during the past four years. In March 2010, the SDPUC approved a $24.1 million increase in interim rates, subject to refund, effective April 1, 2010 for South Dakota customers. On July 7, 2010, the SDPUC approved a final revenue increase of $15.2 million and a base rate increase of $22.0 million with an effective date of April 1, 2010. The approved capital structure and return on equity are confidential. A refund was provided to customers in the third quarter of 2010.

As part of the settlement stipulation, Black Hills Power agreed: (1) to credit customers 65% of off-system sales margins with a minimum credit of $2.0 million per year; (2) that rates will include a South Dakota Surplus Energy Credit of $2.5 million in year one (fiscal year ending March 2011), $2.25 million in fiscal year two, $2.0 million in fiscal year three and zero thereafter; and (3) a moratorium until April 2013 for any base rate increase excluding any extraordinary events as defined in the stipulation agreement; while (4) the SDPUC agreed to adjust the off-system sales portion of the Fuel and Purchased Power Adjustment Clause for the methodology to directly assign renewable resources and firm purchases to the customer load.

(5) On October 19, 2009, Black Hills Power filed a rate case with the WPSC requesting a $3.8 million electric revenue increase to recover costs associated with Wygen III and other generation, transmission and distribution assets and increased operating expenses incurred since 1995. On May 4, 2010, Black Hills Power filed a settlement stipulation agreement with the WPSC for a $3.1 million increase in annual revenues. On May 13, 2010, WPSC approved these new rates based on a return on equity of 10.5% with a capital structure of 52% equity and 48% debt. New rates went into effect on June 1, 2010.

(6) On January 6, 2010, Colorado Electric filed a rate case with CPUC requesting a $22.9 million electric revenue increase to recover increased operating expenses associated with electricity supply contracts, as well as recovery for investment in equipment and electricity distribution facilities necessary to maintain and strengthen the reliability of the electric delivery system in Colorado. On August 5, 2010, the CPUC approved a settlement agreement for $17.9 million in annual revenues with a return on equity of 10.5% and a capital structure of 52% equity and 48% debt. New rates were effective August 6, 2010.

Included in the rate case order was a provision that off-system sales margins be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system sales margins earned beginning August 6, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Colorado Electric is preparing a proposal for a sharing mechanism to be filed with the CPUC.

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 regulate: (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; and (iii) the protection of plant and animal species and minimization of noise emissions.

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.

Environmental Expenditure Estimates	Total (in millions)
2011	$ 12.7
2012	3.8
2013	0.6
Total	$ 17.1

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 and Stormwater permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. 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. Also, the EPA is scheduled to issue updated regulations for wastewater discharge for electric generating units late in 2011, which could have a significant impact on all of our generating fleet.

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 particulate matter, and as of June 23, 2010, Greenhouse Gases. 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.

<u>Clean Air Act</u>

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, Wygen III and Wyodak plants. Without purchasing additional allowances, we currently hold sufficient allowances to satisfy Title IV at all such plants through 2040. 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 of our generating facilities obtain operating permits. All of our existing facilities have received Title V permits, with the exception of Wygen II and Wygen III. Those facilities are allowed to operate under their construction permit until the Title V permits are issued by the state. The Title V application for Wygen II was submitted in 2008, with the permit expected early in 2011. The Wygen III Title V application was submitted in January 2011, with the permit expected in late 2011. Both applications were filed in accordance with regulatory requirements.

On April 29, 2010, the EPA published proposed Industrial and Commercial Boiler regulations, which provide for hazardous air pollutant-related emission limits and monitoring requirements for both major and area sources of hazardous air pollutants. The final rule has a court ordered deadline of February 21, 2011 and we will evaluate once final. If issued as proposed, will have a significant impact on our Neil Simpson I, Osage, Ben French and W.N. Clark facilities. The regulation currently has a three year compliance window and will require engineering evaluations to determine economic viability of continued operations of these units. In our current opinion, the regulations as proposed on April 29, 2010 will lead to retirement of these units within three years of the effective date of the final rule.

The EPA is obligated under a court-approved consent decree to sign a proposed electric utility hazardous air pollutant rule (Utility MACT) by March 16, 2011 and sign its notice of final rule making by November 16, 2011. It is anticipated that affected units will have three years from the rule effective date to be in compliance. In 2010, we participated in the EPA's effort to gather data for rule development. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen II, Wygen III and Wyodak plants.

On June 23, 2010, the EPA published in the Federal register the GHG Tailoring Rule, implementing regulations of GHG for permitting purposes. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source. Existing permitted facilities will see monitoring and reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emission control practices and technologies. As Wyoming state law prohibits regulation of greenhouse gases, the EPA will review and develop requirements for that portion of a new source construction permit or for a major modification of an existing source. It is anticipated this additional process will add several months to the permitting process.

In the 2010 legislative session, the State of Colorado passed House Bill 1365, the Colorado Clean Air Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promote the use of natural gas and other low emitting resources. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Colorado Electric filed testimony with the CPUC that included a proposal recommending retirement of the W.N. Clark facility within three years of promulgation of the EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulation, or in the absence of such regulation, to retire the units by the end of 2017. On December 15, 2010 the CPUC issued an order approving closure of the W.N. Clark plant by December 31, 2013. On January 7, 2011 the State Air Quality Control Commission adopted the CPUC order into the Colorado State Implementation Plan which, after legislative approval, will be a state regulation and will be submitted to EPA Region VIII for approval.

In June 2011, the EPA is scheduled to issue proposed Electric Utility New Source Performance Standards for greenhouse gases. As the regulations are not yet proposed we cannot ascertain their impacts but we anticipate they will be applicable to Wygen III. In 2011 it is anticipated the EPA will finalize a more stringent ozone ambient air standard. If the lower range of the proposed standard is selected, it is anticipated that Campbell County, Wyoming would be a non-attainment area. Under those conditions, the State of Wyoming would evaluate Neil Simpson II, Wygen II and Wygen III for further reductions in NO_x emissions.

Mercury regulations

Approximately 60% of our electric generating capacity is coal-fired. The EPA is scheduled to propose the Utility MACT rule by March 16, 2011 which will, among other pollutants, address mercury emissions at Neil Simpson II, Wygen II and Wygen III.

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 and Wygen III 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. In 2009, we added mercury monitors to our Neil Simpson II plant. The Wygen III plant, which commenced operations in 2010, also has mercury monitors. 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 GHG emissions.

Greenhouse Gas Regulations

We utilize a diversified energy portfolio of assets that includes wind sources and a fuel mix of coal and natural gas. Of these fuels, coal-fired power plants are the most significant sources of CO_2 emissions. Although we cannot predict specifically how, if or when, greenhouse gases will be regulated, any federally mandated GHG reductions or limits on CO_2 emissions could have a material impact on our financial position, results of operations, or cash flows. In 2011, we will be reporting 2010 GHG emissions from our Power Generation and Gas Utilities, in order to comply with the EPA's GHG Annual Inventory regulation, issued in 2009. In addition to federal legislative activity, greenhouse gas regulations have been proposed in various states and alleged climate change issues are the subject of a number of lawsuits, the outcome of which could impact the utility industry. We will continue to review GHG impacts as legislation or regulation develops and litigation is resolved.

New or more stringent regulations or other energy efficiency 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, the acquisition or development of additional energy supply from renewable resources, 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, including utility affiliates. 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.

In connection with GHG 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 mandated at the federal level or in other state 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 or may be 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 waste from flue gas and sulfur removal from the Wyodak, Neil Simpson I, Ben French, Neil Simpson II, Wygen II and Wygen III plants are deposited in mined areas at the WRDC coal mine. These disposal areas are located below some shallow water aquifers in the mine. In 2009, the State of Wyoming confirmed their past approval of this practice but may re-evaluate and 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 waste from the burning of coal is currently classified as hazardous material, but the waste does contain minute traces of metals that could be perceived as polluting if such metals leached into underground water. We conducted investigations which concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality. We have suspended operations at the Osage power plant as of October 1, 2010. It has an on-site ash impoundment that is near capacity. An application to close the impoundment was filed with the State of Wyoming on November 3, 2010 and any future ash disposal will be at the Wyodak coal mine. Our 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 and MEAN to be responsible for any such costs related to the solid waste from their ownership interest in the Wyodak plant and Wygen I plant, respectively.

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. On June 21, 2010, the EPA published in the Federal Register the proposed coal combustion residuals regulations. The regulations are complex and contain various options for ash management that the EPA will be selecting from to form the final version of the rule. We cannot determine the likely impact on our operations until the final version of the rule is known, which is currently expected to be mid-2011. However, if ash becomes subject to regulations as a hazardous waste, implementation requirements could have a material impact on our financial position or results of operations.

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 sites. In 2010, we undertook a third party review to obtain an updated estimate of remedial costs. From that review, obligations are estimated at between $3.6 million and $6.8 million. The acquisition also provided for a $1.0 million insurance recovery, now valued at $1.1 million, which will be used to help offset remediation costs. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the 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 with other potentially responsible parties when and where permitted.

Non-regulated Energy Group

Our Non-regulated Energy Group, which operates through various subsidiaries, produces natural gas and crude oil primarily in the Rocky Mountain region; produces and sells electric capacity and energy through ownership of a portfolio of generating plants; produces and stores coal; and engages in natural gas, crude oil, coal, power and environmental marketing. 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, 2010, the principal assets of our Oil and Gas segment included: (i) operating interests in oil and natural gas properties, including properties in the San Juan Basin (primarily New Mexico, including holdings within the tribal lands of the Jicarilla Apache and Southern Ute Nations), the Powder River Basin (Wyoming) and the Piceance Basin (primarily in Colorado); (ii) non-operated interests in oil and natural gas properties including wells located in the Williston (Bakken Shale primarily in North Dakota), Wind River (Wyoming), Bearpaw Uplift (Montana), Arkoma (Oklahoma), Anadarko (Texas) and Sacramento (California) basins; and (iii) a 44.7% ownership interest in the Newcastle gas processing plant and associated gathering system located in Weston County, Wyoming. The plant, 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, 2010, we had total reserves of approximately 131 Bcfe, of which natural gas comprised 73% and oil comprised 27% of total reserves. The majority of our reserves are located in select oil and natural gas producing basins in the Rocky Mountain region. Approximately 28% of our reserves are located in the San Juan Basin of northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County, 26% are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field of Weston and Niobrara counties and 25% are located in the Piceance Basin of western Colorado.

Delivery Commitments

None of our oil and gas production is sold under long-term product delivery commitments.

Summary Oil and Gas Reserve Data

The summary information presented concerning our estimated proved developed and undeveloped oil and gas reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by CG&A, an independent consulting and engineering firm located in Fort Worth, Texas. Reserves in 2010 and 2009 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period 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. Our 2008 reserves were determined based on the previous guidelines utilizing the price on the last day of the reporting period. (Oil (in Mbbl) is multiplied by six to convert to MMcfe). Additional information on our oil and gas reserves, related financial data and the SEC requirements can be found in Note 21 to the Consolidated Financial Statements in this Annual Report on Form 10-K.

The Company believes it maintains adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interest and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. The Company's internal engineers and our independent reserve engineering firm, CG&A, work independently and concurrently to develop reserve volume estimates. Current revenue and expense information is obtained from the Company's accounting records, which are subject to external quarterly reviews, annual audits and internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. The Company's current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated in the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support materials have been assembled, CG&A meets with the Company's technical personnel to review field performance and future development plans in order to further verify their validity. Following these reviews the reserve database, including updated cost, price and ownership data, is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to the Company's reserve database is restricted to specific members of the engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas and has over 22 years of practical experience in petroleum engineering and over 20 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

BHEP's Manager of Planning and Analysis is the technical person primarily responsible for overseeing our third party reserve estimates. He has over 30 years of Exploration and Production industry experience as a geologist. He has over 20 years of experience working closely with internal and third party qualified reserve estimators in major and mid-sized oil and gas companies. He holds a Bachelor of Science degree in Geology and a Masters in Business Administration.

The following tables set forth summary information concerning our estimated proved developed and undeveloped reserves, by basin, as of December 31, 2010, 2009 and 2008:

Proved Reserves	**December 31, 2010**					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	67,656	11,475	36,281	679	10,180	9,041
Oil (Mbbl)	4,434	—	11	508	3,891	24
Total Developed (MMcfe)	94,260	11,475	36,347	3,727	33,526	9,185
Undeveloped -						
Natural Gas (MMcf)	27,800	21,777	620	1,820	—	3,583
Oil (Mbbl)	1,506	—	—	1,506	—	—
Total Undeveloped (MMcfe)	36,836	21,777	620	10,856	—	3,583
Total MMcfe	131,096	33,252	36,967	14,583	33,526	12,768

Proved Reserves	**December 31, 2009**					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	74,911	14,247	39,276	237	10,711	10,440
Oil (Mbbl)	4,274	—	7	162	4,068	37
Total Developed (MMcfe)	100,555	14,247	39,318	1,209	35,119	10,662
Undeveloped -						
Natural Gas (MMcf)	12,749	5,054	3,030	768	460	3,437
Oil (Mbbl)	1,000	—	—	516	484	—
Total Undeveloped (MMcfe)	18,749	5,054	3,030	3,864	3,364	3,437
Total MMcfe	119,304	19,301	42,348	5,073	38,483	14,099

Proved Reserves	December 31, 2008					
	Total	Piceance	San Juan	Williston	Powder River	Other
Developed -						
Natural Gas (MMcf)	88,701	18,194	48,168	303	10,303	11,733
Oil (Mbbl)	4,429	—	13	220	4,163	33
Total Developed (MMcfe)	115,275	18,194	48,246	1,623	35,281	11,931
Undeveloped -						
Natural Gas (MMcf)	65,731	36,728	16,090	508	421	11,984
Oil (Mbbl)	756	—	—	303	444	9
Total Undeveloped (MMcfe)	70,267	36,728	16,090	2,326	3,085	12,038
Total MMcfe	185,542	54,922	64,336	3,949	38,366	23,969

The following table summarizes quantities of proved developed and undeveloped reserves by basin, estimated using SEC-defined product prices, as of December 31, 2010, 2009 and 2008:

Oil	December 31, 2010					
(in Mbbl)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,274	—	7	678	4,552	37
Production	(376)	—	(2)	(84)	(280)	(10)
Additions - acquisitions	(13)	—	—	—	—	(13)
Additions - extensions and discoveries	1,145	—	—	1,099	46	—
Revisions to previous estimates	(90)	—	6	321	(427)	10
Balance at end of year	5,940	—	11	2,014	3,891	24

Natural Gas	December 31, 2010					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	87,660	19,301	42,306	1,005	11,171	13,877
Production	(8,484)	(1,077)	(5,056)	—	(314)	(2,037)
Additions - acquisitions	(377)	—	—	—	—	(377)
Additions - extensions and discoveries	1,710	—	372	1,334	—	4
Revisions to previous estimates	14,947	15,028	(721)	160	(677)	1,157
Balance at end of year	95,456	33,252	36,901	2,499	10,180	12,624

	December 31, 2010					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	119,304	19,301	42,348	5,073	38,483	14,099
Production	(10,740)	(1,077)	(5,068)	(504)	(1,994)	(2,097)
Additions - acquisitions	(455)	—	—	—	—	(455)
Additions - extensions and discoveries	8,580	—	372	7,928	276	4
Revisions to previous estimates	14,407	15,028	(685)	2,086	(3,239)	1,217
Balance at end of year	131,096	33,252	36,967	14,583	33,526	12,768

Oil

(in Mbbl)	December 31, 2009 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,185	—	13	523	4,607	42
Production	(366)	—	(3)	(32)	(321)	(10)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	152	—	—	152	—	—
Revisions to previous estimates	303	—	(3)	35	266	5
Balance at end of year	5,274	—	7	678	4,552	37

Natural Gas

(in Mbbl)	December 31, 2009 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	154,432	54,922	64,258	811	10,724	23,717
Production	(9,710)	(1,263)	(5,571)	—	(297)	(2,579)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	2,560	—	2,135	222	—	203
Revisions to previous estimates	(59,622)	(34,358)	(18,516)	(28)	744	(7,464)
Balance at end of year	87,660	19,301	42,306	1,005	11,171	13,877

Total MMcfe	December 31, 2009 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	185,542	54,922	64,336	3,949	38,366	23,969
Production	(11,906)	(1,263)	(5,589)	(192)	(2,223)	(2,639)
Additions - acquisitions	—	—	—	—	—	—
Additions - extensions and discoveries	3,472	—	2,135	1,134	—	203
Revisions to previous estimates	(57,804)	(34,358)	(18,534)	182	2,340	(7,434)
Balance at end of year	119,304	19,301	42,348	5,073	38,483	14,099

Oil

(in Mbbl)	December 31, 2008 Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	5,807	—	3	243	5,504	57
Production	(387)	—	(5)	(27)	(339)	(16)
Additions - acquisitions	2	—	—	—	—	2
Additions - extensions and discoveries	438	—	—	280	19	139
Revisions to previous estimates	(675)	—	15	27	(577)	(140)
Balance at end of year	5,185	—	13	523	4,607	42

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Natural Gas	**December 31, 2008**					
(in MMcf)	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	172,964	64,887	77,770	386	13,201	16,720
Production	(10,704)	(980)	(6,448)	—	(347)	(2,929)
Additions - acquisitions	3,352	—	—	—	—	3,352
Additions - extensions and discoveries	4,037	218	—	438	135	3,246
Revisions to previous estimates	(15,217)	(9,203)	(7,064)	(13)	(2,265)	3,328
Balance at end of year	154,432	54,922	64,258	811	10,724	23,717

	December 31, 2008					
Total MMcfe	Total	Piceance	San Juan	Williston	Powder River	Other
Balance at beginning of year	207,806	64,887	77,788	1,844	46,225	17,062
Production	(13,026)	(980)	(6,478)	(162)	(2,381)	(3,025)
Additions - acquisitions	3,364	—	—	—	—	3,364
Additions - extensions and discoveries	6,665	218	—	2,118	249	4,080
Revisions to previous estimates	(19,267)	(9,203)	(6,974)	149	(5,727)	2,488
Balance at end of year	185,542	54,922	64,336	3,949	38,366	23,969

Production Volumes

	December 31, 2010		
Location	Oil (in Bbl)	Natural Gas (Mcfe)	Total (Mcfe)
San Juan	2,403	5,055,635	5,070,053
Piceance	—	1,111,724	1,111,724
Powder River	280,351	842,385	2,524,491
Williston	84,472	—	506,832
All other properties	8,419	2,036,755	2,087,269
Total Volume	375,645	9,046,499	11,300,369

	December 31, 2009		
Location	Oil (in Bbl)	Natural Gas (Mcfe)	Total (Mcfe)
San Juan	2,547	5,570,741	5,586,023
Piceance	—	1,298,924	1,298,924
Powder River	320,752	818,709	2,743,221
Williston	32,311	—	193,866
All other properties	10,342	2,578,498	2,640,550
Total Volume	365,952	10,266,872	12,462,584

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Location	December 31, 2008 Oil (in Bbl)	Natural Gas (Mcfe)	Total (Mcfe)
San Juan	5,095	6,447,964	6,478,534
Piceance	—	1,003,062	1,003,062
Powder River	338,797	829,949	2,862,731
Williston	26,754	—	160,524
All other properties	16,781	2,928,428	3,029,114
Total Volume	387,427	11,209,403	13,533,965

	December 31, 2010	December 31, 2009
Proved developed reserves as a percentage of total proved reserves on an MMcfe basis	72 %	84 %
Proved undeveloped reserves as a percentage of total proved reserves on an MMcfe basis	28 %	16 %
Present value of estimated future net revenues, before tax (in thousands)	$ 196,554	$ 134,322

The following table reflects average wellhead pricing used in the determination of the reserves:

	Total	Piceance	San Juan	Williston	Powder River	Other
December 31, 2010						
Gas per Mcf	$ 3.45	$ 3.21	$ 3.50	$ 3.57	$ 3.62	$ 3.79
Oil per Bbl	$ 70.82	$ —	$ 66.36	$ 69.32	$ 71.62	$ 68.52
December 31, 2009						
Gas per Mcf	$ 2.52	$ 1.57	$ 2.58	$ 4.84	$ 2.72	$ 3.82
Oil per Bbl	$ 53.59	$ —	$ 52.31	$ 52.64	$ 53.77	$ 49.16

Drilling Activity

The following tables reflect the wells completed through our drilling activities for the last three years. In 2010, we participated in drilling 21 gross (9 net) development and exploratory wells, with a net well success rate of 100%. 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,	2010		2009		2008	
Net Development wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	—	—	3.62	—
San Juan	5.60	—	3.00	—	6.70	1.00
Williston	0.67	—	0.04	—	0.31	0.14
Powder River	2.66	—	—	—	3.75	—
Other	—	—	4.37	1.04	10.17	2.18
Total net developed wells	8.93	—	7.41	1.04	24.55	3.32

Year ended December 31,	2010		2009		2008	
Net Exploratory wells	Productive	Dry	Productive	Dry	Productive	Dry
Piceance	—	—	0.91	—	—	—
San Juan	—	—	—	—	2.00	—
Williston	—	—	0.03	—	0.76	—
Powder River	—	—	—	0.50	0.75	—
Other	—	—	0.50	0.37	—	—
Total net exploratory wells	—	—	1.44	0.87	3.51	—

As of December 31, 2010, we were participating in the drilling of 6 gross (0.75 net) wells, which had been commenced but not yet completed.

Recompletion Activity

Recompletion activities for the years ended December 31, 2010, 2009 and 2008 were insignificant to our overall oil and gas operations.

Productive Wells

The following table summarizes our gross and net productive wells at December 31, 2010, 2009 and 2008:

	December 31, 2010					
	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	463	1	2	38	418	4
Natural Gas	828	88	225	—	7	508
Total	1,291	89	227	38	425	512
Net Productive:						
Oil	312.09	—	1.91	2.46	307.23	0.49
Natural Gas	355.90	66.23	214.82	—	0.73	74.12
Total	667.99	66.23	216.73	2.46	307.96	74.61

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December 31, 2009	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	454	1	2	29	416	6
Natural Gas	860	86	220	—	20	534
Total	1,314	87	222	29	436	540
Net Productive:						
Oil	314.47	—	1.91	2.51	309.40	0.65
Natural Gas	355.20	65.93	210.21	—	2.50	76.56
Total	669.67	65.93	212.12	2.51	311.90	77.21

December 31, 2008	Total	Piceance	San Juan	Williston	Powder River	Other
Gross Productive:						
Oil	414	1	2	12	395	4
Natural Gas	682	74	158	—	7	443
Total	1,096	75	160	12	402	447
Net Productive:						
Oil	314.65	—	1.91	1.78	310.45	0.51
Natural Gas	287.20	55.00	152.11	—	0.87	79.22
Total	601.85	55.00	154.02	1.78	311.32	79.73

Acreage

The following table summarizes our undeveloped, developed and total acreage by location as of December 31, 2010:

	Undeveloped		Developed		Total	
	Gross	Net *	Gross	Net	Gross	Net
Piceance	40,881	31,347	35,497	31,460	76,378	62,807
San Juan	40,908	39,489	27,232	24,136	68,140	63,625
Williston	26,078	3,875	16,756	1,874	42,834	5,749
Powder River	54,113	38,074	27,389	17,110	81,502	55,184
Bearpaw Uplift (MT)	417,753	73,940	100,364	18,845	518,117	92,785
Other	68,735	45,420	30,200	5,988	98,935	51,408
Total	648,468	232,145	237,438	99,413	885,906	331,558

* Approximately 5.3% (43,135 gross and 12,232 net acres) and 4.3% (46,935 gross and 10,048 net acres) and 14.4% (122,688 gross and 33,473 net acres) of our net undeveloped acreage could expire in 2011, 2012 and 2013, respectively, if production is not established on the leases or further action is not taken to extend the associated lease terms. Decisions on extending leases are based on expected exploration or development potential under the prevailing economic conditions.

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 a 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, which sometimes results 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 Office of Natural Resources Revenue and the Bureau of Indian Affairs, along with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas operations and administration of royalties on federal onshore and tribal lands. In addition, the Bureau of Indian Affairs and each Native American tribe promulgate and enforce additional regulations pertaining to oil and natural gas operations and administration of taxes 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 expansion and 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 last several years. For example, in 2008 new state regulations were implemented in New Mexico which increased the regulatory requirements associated with drilling pits. Colorado legislation in 2007 changed the structure of the oil and gas commission, which has subsequently developed and approved significant changes to oil and gas regulations which were implemented in 2009. Changes such as these have increased costs and added uncertainty with respect to the timing and receipt of permits. We expect additional changes of this nature to occur in the future.

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 the 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.

Greenhouse Gas Regulations. 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 GHG emissions, beginning with calendar year 2008. The EPA published an amendment to its GHG reporting requirements in the November 30, 2010 Federal Register, adding Petroleum and Natural Gas Systems to the mandatory reporting requirements. Data gathering commenced on January 1, 2011, with the final report to the EPA due in 2012. Other states may implement their own 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 our non-regulated power plants. As of December 31, 2010, we held varying interests in independent power plants operating in Wyoming and Idaho with a total net ownership of 120 MW. In January 2011, we sold our ownership interests in the Idaho partnerships which own the Idaho facilities.

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. See Notes 1 and 22 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 a substantial majority of our non-regulated 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, 2010, the power plant ownership interests held by our Power Generation segment included:

Power Plants[1]	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	Start Date
Gillette CT	Gas	Gillette, Wyoming	100.0 %	40.0	2001
Wygen I[2]	Coal	Gillette, Wyoming	76.5 %	68.9	2003
Glenns Ferry Cogeneration [3]	Gas	Glenns Ferry, Idaho	50.0 %	5.5	1996
Rupert Cogeneration [3]	Gas	Rupert, Idaho	50.0 %	5.5	1996

(1) We are currently constructing two 100 MW combined-cycle gas-fired power generation facilities in Colorado. These facilities are expected to be completed by December 31, 2011.
(2) In January 2009, we sold a 23.5% ownership interest in this plant to MEAN. See Note 22 of Notes to our Consolidated Financial Statements for further description of the transaction.
(3) On January 18, 2011, we sold our ownership interest in the partnerships which owns the Glenns Ferry and Rupert Cogeneration facilities.

Gillette CT. The Gillette CT is a simple-cycle, gas-fired combustion turbine located at our Gillette, Wyoming 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 generation facility is a mine-mouth, coal-fired power plant with a total nameplate capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant. We sell 60 MW of unit contingent capacity and energy from this plant to Cheyenne Light under a PPA that expires on December 31, 2022. The PPA includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership interest in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW which is equivalent to the estimated initial per MW price of new construction of the Wygen III facility. This price is reduced annually by an amount of annual depreciation assuming a facility life of 35 years.

Idaho Cogeneration Facilities. Through partnership investments, at December 31, 2010, we owned a 50% interest in two QFs in Rupert and Glenns Ferry, Idaho. Rupert and Glenns Ferry are both 11 MW combined-cycle, gas-fired power plants. Our investments in the partnerships have been accounted for under the equity method of accounting. On January 18, 2011, we sold our ownership interests in the partnerships which own the Idaho facilities.

Black Hills Colorado IPP. During 2009, we began planning and purchasing equipment for the construction of two 100 MW combined-cycle gas-fired power generation facilities to fulfill a 20-year PPA signed with Colorado Electric. Construction of the facilities commenced in July 2010, and these facilities are expected to be completed by December 31, 2011.

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, 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, 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 their own upside opportunity for independent power producers in some regions.

Regulation. Many of the environmental laws and regulations applicable to our regulated 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.

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: Wygen I and Gillette CT. 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 regulated 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 I plants through 2040, without purchasing additional allowances. The EPA's pending Utility MACT described in the Utilities Group section will apply to Wygen I. The EPA's GHG Tailoring Rule described in the Utilities Group section will apply to the Gillette CT and Wygen I, upon a major modification or upon operating permit renewal.

Clean Water Act. The Clean Water Act impacts our Power Generation business in a manner similar to the impact described above for our regulated 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.

Greenhouse Gas Regulations. 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, process and sell 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. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 5.9 million tons of coal in 2010. In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended towards a ratio of approximately 2.3:1, 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 federal and state royalties of 12.5% and 9.0%, respectively, of the selling price of all coal. As of December 31, 2010, we had coal reserves of approximately 261.9 million tons, based on internal engineering studies. The reserve life is equal to approximately 40 years at expected production levels.

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

- Our regulated 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;

- The 110 MW Wygen III power plant owned 52% by Black Hills Power, 25% by MDU and 23% by the City of Gillette;
- Our 90 MW non-regulated mine-mouth power plant, Wygen I owned 76.5% by Black Hills Wyoming and 23.5% by MEAN; 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 these affiliate 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 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.

We increased our coal production to supply additional mine-mouth power generating capacity related to the 110 MW Wygen III plant, which began commercial operations in April 2010. Coal supply agreements provide WRDC will supply the coal to Wygen III through June 1, 2060 under an agreement that limits earnings from these affiliate coal sales to a specified return on our coal mines' 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.

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

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. There are limitations on our ability to economically transport our lower-heat content coal, but we are reviewing new opportunities to market our coal.

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. Many of the environmental issues and regulations discussed under the Utilities Group also apply to our Coal Mining segment.

Operations at WRDC must, and regularly do attend to issues arising due to the proximity of the mine disturbance boundary to the City of Gillette and to related residential and industrial development. The impacts from mining are routinely viewed negatively by the general public and increasing complaints and challenges to the permits may occur as mining operations move closer to the development areas. Specific concerns include fugitive dust emissions and vibration and nitrous oxide fumes from blasting. To mitigate these concerns, WRDC is actively pursuing the establishment of buffer zones through land purchases and long-term leases.

Ash from our South Dakota and Wyoming power plants, as well as PacifiCorp's Wyodak Power Plant, is disposed of in the mine and is utilized for backfill to meet permitted post-mining contour requirements. The EPA has proposed national disposal regulations that include multiple options, one of which regulates coal ash as a hazardous waste. The public comment period ended on November 19, 2010, and a final rule is expected in late 2011 or early 2012. While the proposed combustion residuals regulations do not address mine backfill, it is widely expected that the U.S. Office of Surface Mining will collaborate with the EPA to address mine backfill in the near future. If the ash is regulated as a hazardous waste, implementation requirements could have a material impact on our financial position and results of operations.

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 the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five year mining permit issued by the State of Wyoming. The current permit expires in April 2011 and an application for renewal has been timely filed. Based on extensive reclamation studies, we have accrued approximately $17.6 million for reclamation costs as of December 31, 2010. If additional requirements or changes to current requirements are imposed in the future, we may experience a material increase in reclamation costs. The mining operation must also meet specific environmental performance standards regulated by the WDEQ through permit commitments

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and statutes. Failure to achieve these standards could potentially delay the release of the bonds and/or result in increased mitigation costs.

Energy Marketing Segment

Through our subsidiary, Enserco, we engage in natural gas, crude oil, coal, power and environmental marketing and trading in the United States and Canada. Our marketing operations are headquartered in Denver, Colorado, with a satellite sales office in Calgary, Alberta, Canada.

Our energy marketing business seeks to provide services to producers and end-users of natural gas, crude oil, coal, power and environmental products and to capitalize on market volatility by employing certain risk-managed commodity trading strategies. The diversity of the commodities portfolio that we market helps us optimize value for shareholders. 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 independent 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. Our coal marketing team assists small utility and industrial coal consumers manage their coal procurement and transportation functions. Similarly, our power marketing experts help both buyers and sellers of electricity, as well as assisting customers with the monetization of emissions or other environmental products.

Our natural gas marketing focuses primarily on producer services and wholesale marketing. It includes the purchase, sale, storage and transportation of natural gas, as well as a variety of services including asset optimization, price risk management and customized offerings to producer and end-use clients. Producer services margins are typically fee-based, limited risk, recurrent transactions with long-term customers. Additionally, the producer services division has captured increased opportunities for growth with the recent shale natural gas discoveries. The team's wholesale efforts are focused in the Rocky Mountain, Western and Mid-Continent regions of the United States, the entirety of Canada, and expanding into the eastern United States.

Our crude oil marketing focuses on providing optimization services to both producers and end-use markets in the Rocky Mountain States with an emphasis in the Bakken Shale of North Dakota. With exclusive trucking arrangements and access to all major Rockies pipelines, Enserco extends to its customers the benefit of established relationships with premium markets and transportation options via pipeline, truck and rail. Enserco is continuing to build out its truck unloading stations and currently has six strategically located stations in North Dakota, Wyoming and Colorado as well as crude oil storage in Wyoming. Enserco's crude oil marketing team provides us with a low risk, recurring margin stream.

Enserco began marketing coal in June 2010 with the acquisition of a coal marketing business. Our coal marketing team currently participates in financial and physical coal markets, primarily focused in coal basins west of the Mississippi River. Our presence spans the physical coal supply chain from sourcing, storage and delivery. We leverage extensive experience and partnering arrangements to meet the challenges facing the physical markets. Further, we maintain long-term supply positions from multiple sources in multiple basins, including Wyoming's Powder River and Uinta Basins that allow us to perform beyond the role of a traditional merchant participant and closer to a primary supplier via supply sourcing flexibility and security.

Enserco began power and environmental marketing late in the third quarter of 2010. FERC approval was received for power marketing in December 2010 with an effective date of September 1, 2010. The power marketing focuses on origination and customer business with an emphasis on a diversified portfolio of short, mid- and long-term transactions. The marketing effort primarily involves execution of financial transactions, at liquid trading hubs in day-ahead markets. The geographic scope encompasses the United States.

Environmental marketing focuses on producer services and customized solutions for all aspects of the renewable business. This strategy encompasses short, mid- and longer term origination efforts with end users. Our marketers monetize Renewable Energy Credits, carbon and other emissions as well as optimize renewable assets including solar, wind and biomass. The focus is on opportunities within the United States, both in mandatory and elective markets.

Our average daily marketing physical volumes for the year ended December 31, 2010 were approximately 1.6 million MMBtu of gas, approximately 18,455 Bbls of oil and approximately 33,250 tons of coal.

Our total gross margin recognized for each of the following years was derived from our marketing strategies according to the following (in millions):

	2010		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$ 20.6	$ 0.2	$ 20.8
Natural Gas Wholesale trading (transportation)	5.5	(7.9)	(2.4)
Producer services (natural gas)	3.8	(0.5)	3.3
Producer services (crude oil)	8.9	1.6	10.5
Coal marketing *	1.6	2.0	3.6
Power marketing *	(2.5)	(1.4)	(3.9)
Environmental marketing *	—	—	—
	37.9	(6.0)	31.9
Wholesale trading (proprietary and other)	(5.4)	1.5	(3.9)
Total gross margin	$ 32.5	$ (4.5)	$ 28.0

* Includes coal marketing commencing in June 2010 and power and environmental marketing commencing in the third quarter of 2010.

	2009		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$ 2.2	$ (1.7)	$ 0.5
Natural Gas Wholesale trading (transportation)	10.9	5.5	16.4
Producer services (natural gas)	4.3	0.4	4.7
Producer services (crude oil)	11.3	(8.2)	3.1
	28.7	(4.0)	24.7
Wholesale trading (proprietary and other)	12.7	(24.0)	(11.3)
Total gross margin	$ 41.4	$ (28.0)	$ 13.4

	2008		
	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural Gas Wholesale trading (storage)	$ 6.6	$ 4.0	$ 10.6
Natural Gas Wholesale trading (transportation)	13.7	4.1	17.8
Producer services (natural gas)	6.0	(0.2)	5.8
Producer services (crude oil)	1.0	6.6	7.6
	27.3	14.5	41.8
Wholesale trading (proprietary and other)	(7.7)	25.2	17.5
Total gross margin	$ 19.6	$ 39.7	$ 59.3

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The tables below summarize our realized and unrealized gross margins by product and strategy. Producer Services and Other Recurrent are marketing strategies that are typically fee-based, limited risk, recurrent transactions with long-term customers. Asset based strategies are marketing strategies that involve trading around assets, commonly of the storage and transportation variety. These strategies typically have limited and quantifiable downside and higher upside potential.

	2010					
	Natural Gas	Crude Oil	Coal *	Power *	Environmental *	Total
Realized -						
Producer Services and Other Recurrent	$ 3.8	$ 5.7	$ 1.1	$ —	$ —	$ 10.6
Asset Based	23.8	3.2	—	—	—	27.0
Proprietary and Other	(3.0)	—	0.4	(2.5)	—	(5.1)
Total realized	24.6	8.9	1.5	(2.5)	—	32.5
Unrealized -						
Producer Services and Other Recurrent	(0.5)	2.9	1.4	—	—	3.8
Asset Based	(7.7)	(1.3)	—	—	—	(9.0)
Proprietary and Other	1.4	0.1	0.6	(1.4)	—	0.7
Total unrealized	(6.8)	1.7	2.0	(1.4)	—	(4.5)
Total -						
Producer Services and Other Recurrent	3.3	8.6	2.5	—	—	14.4
Asset Based	16.1	1.9	—	—	—	18.0
Proprietary and Other	(1.6)	0.1	1.0	(3.9)	—	(4.4)
Total	$ 17.8	$ 10.6	$ 3.5	$ (3.9)	$ —	$ 28.0

* Includes coal marketing commencing in June 2010 and power and environmental marketing commencing in the third quarter of 2010.

	2009		
	Natural Gas	Crude Oil	Total
Realized -			
Producer Services and Other Recurrent	$ 4.3	$ 8.4	$ 12.7
Asset Based	13.2	2.9	16.1
Proprietary and Other	12.6	—	12.6
Total realized	30.1	11.3	41.4
Unrealized -			
Producer Services and Other Recurrent	0.4	(6.8)	(6.4)
Asset Based	3.8	(1.5)	2.3
Proprietary and Other	(23.9)	—	(23.9)
Total unrealized	(19.7)	(8.3)	(28.0)
Total -			
Producer Services and Other Recurrent	4.7	1.6	6.3
Asset Based	17.0	1.4	18.4
Proprietary and Other	(11.3)	—	(11.3)
Total	$ 10.4	$ 3.0	$ 13.4

	2008		
	Natural Gas	Crude Oil	Total
Realized -			
Producer Services and Other Recurrent	$ 6.0	$ 3.1	$ 9.1
Asset Based	20.3	(2.1)	18.2
Proprietary and Other	(7.7)	—	(7.7)
Total realized	18.6	1.0	19.6
Unrealized -			
Producer Services and Other Recurrent	(0.2)	4.4	4.2
Asset Based	8.1	2.2	10.3
Proprietary and Other	25.2	—	25.2
Total unrealized	33.1	6.6	39.7
Total -			
Producer Services and Other Recurrent	5.8	7.5	13.3
Asset Based	28.4	0.1	28.5
Proprietary and Other	17.5	—	17.5
Total	$ 51.7	$ 7.6	$ 59.3

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 upside potential and definable downside risk. Of these contractual positions, 62% 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 by region at December 31, 2010 were as follows:

	Term Until Expiration			
Region	Less than 2 Years (2011 and 2012)	2 to 4 Years (2013 - 2016)	Greater than 4 Years (2017 and beyond)	Total Volume
		(Bcf of natural gas)		
Rockies	46.59	47.67	3.49	97.75
West	89.24	9.00	8.63	106.87
MidContinent	7.86	—	—	7.86
Total Capacity	143.69	56.67	12.12	212.48

The firm storage capacity rights we held by region at December 31, 2010 included:

Region	Volume (Bcf)	Term	
MidContinent/Upper Midwest	1.0	1/11-3/17	
MidContinent/Upper Midwest	1.0	1/11-3/12	*
MidContinent/Upper Midwest	1.0	1/11-3/13	*
MidContinent/Upper Midwest	1.0	1/11-3/12	
MidContinent/Upper Midwest	0.3	1/11-3/13	
West/Northwest	1.0	1/11-3/12	

* Indicates right-of-first-refusal to extend the capacity right following the expiration of the current term.

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The following table summarizes the gas, oil and coal inventory at our Energy Marketing segment at December 31. In most cases, these commodities are being held in inventory to capture the price differential between the time purchased and a subsequent sales date in the future. In some cases, volumes are held to meet operational requirements. A high percentage of the inventory has been sold forward or hedged forward to lock in a margin upon future withdrawal.

	2010	2009
Gas inventory volumes (MMBtu)	14,922,353	12,177,802
Crude inventory volumes (Bbl)	198,052	69,045
Coal inventory volumes (Ton)	1,529	—

Competition. The energy marketing industry is characterized by numerous large 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 create volatility in natural gas prices. The impact of these conditions typically occurs in the fourth and first quarters of our fiscal year, resulting in higher margin opportunities. Due to these seasonal fluctuations in demand and prices, 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 component of the business requires significant working capital investment in the form of inventory. Those investment levels vary as market opportunities change but have historically been higher in the second and third quarters of our fiscal year.

Regulation. Enserco is subject to the jurisdiction of the FERC, FTC and CFTC with respect to its marketing activities. With respect to its import and export of commodities, Enserco is also subject to the jurisdiction of the US Department of Energy, the US Department of Commerce, Canada's National Energy Board, and Alberta's Energy Resources Conservation Board, as well as US and Canadian Customs.

Other Properties

We own an eight-story, 67,000 square foot office building in Rapid City, South Dakota, where our corporate headquarters is located. Also in Rapid City, we own an office building consisting of approximately 36,000 square feet, and a warehouse building and shop with approximately 30,410 square feet. Our Gas Utilities own various office, service center and warehouse space totaling over 170,000 square feet throughout their service territories in Nebraska, Iowa, Colorado and Kansas. In Cheyenne, Wyoming, we own a business office with approximately 13,400 square feet, and a service center and garage with an aggregate of approximately 28,300 square feet. We also own other offices and warehouses located within our service areas.

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

- Approximately 8,800 square feet for an operations and customer call center in Rapid City, South Dakota;
- Approximately 62,160 square feet of office space in Omaha, Nebraska;
- Approximately 37,600 square feet for a customer call center in Lincoln, Nebraska;
- Approximately 47,430 square feet of office space in Denver, Colorado; and
- Other offices and warehouse facilities located within our service areas.

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.

We are currently constructing an office building in Papillion, Nebraska totaling approximately 36,000 square feet which is expected to be completed in May 2011.

Employees

At December 31, 2010, we had 2,124 full-time employees. Approximately 33% of the Company's employees are represented by a collective bargaining agreement. Out of a total of six collective bargaining agreements, three of these agreements are either currently in negotiations or planned for renewal negotiations during the first quarter of 2011. We have experienced no labor stoppages in recent years. At December 31, 2010, approximately 22% of our Utilities Group employees were eligible for regular or early retirement.

The following table sets forth the number of employees by business group:

	Number of Employees
Corporate	367
Utilities	1,505
Non-regulated Energy	252
Total	2,124

At December 31, 2010, 705 employees (all within the Utilities Group), were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Black Hills Power	174	IBEW Local 1250	March 31, 2012
Cheyenne Light	56	IBEW Local 111	June 30, 2011
Colorado Electric	147	IBEW Local 667	April 15, 2011
Iowa Gas	139	IBEW Local 204	April 27, 2010
Kansas Gas	24	Communications Workers of America, AFL-CIO Local 6407	December 31, 2011
Nebraska Gas	165	IBEW Local 244	December 31, 2009
Total	705		

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ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. 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.

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 electric and gas utility operations are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility 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 are able to 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 have deferred a substantial amount of income tax related to various tax planning strategies including the deferral of a gain associated with the assets sold in the IPP Transaction. If the Internal Revenue Service successfully challenges these tax positions, our results of operations, financial position or liquidity could be adversely affected.

We have deferred a substantial amount of tax payments through various tax planning strategies, including the deferral of approximately $125 million in taxes associated with the IPP Transaction and the Aquila Transaction. We had previously deferred approximately $185 million in taxes associated with the IPP Transaction and the Aquila Transaction, and in the third quarter of 2010, we reached an agreement with the Appeals Division of the IRS that resulted in a decrease in the amount of such deferral from $185 million to $125 million. The decrease represents the downward adjustment to tax depreciation allowed on certain assets sold, which resulted in a decrease to the gain realized on the sale of those assets and ultimately a decrease in deferred taxes. The remaining $125 million in deferred taxes relating to the IPP Transaction and the Aquila Transaction continues to be subject to IRS review.

We cannot be certain that the IRS will accept our tax positions. If the IRS successfully sought to assert contrary tax positions, we could be required to pay a significant amount of these deferred taxes earlier than currently forecasted. In certain circumstances, the IRS may assess penalties when challenging our tax positions. If we were unsuccessful in defending against these penalties, it may have a material impact on our 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, SEC-defined commodity prices and recent costs are utilized. 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 SEC-defined 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 first quarter of 2009 and fourth quarter of 2008 due to the full cost ceiling limitations. We may have to record additional non-cash impairment charges in the future if commodity prices drive the SEC-defined prices below levels that precipitated the 2009 and 2008 impairments. See Note 12 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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.

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.

Municipal governments may seek to limit or deny franchise privileges.

Municipal governments within our utility service territories possess the power of condemnation, and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations, and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

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 development, expansion and acquisition activities. We can provide no assurance that we will be able to complete development projects or acquisitions 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 utility services in our target markets;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves and our coal-fired generation capacity;
- 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.

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 along with the cost of complying with or satisfying conditions imposed upon such approvals;
- Contractual 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;
- The cost of recruiting and retaining or the unavailability of skilled labor;
- 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 variations from normal weather conditions.

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. Because natural gas is primarily 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 than normal in the summer and warmer than normal 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 some of 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 contract and off-system 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 productivity and profitability could be lower than our current expectations. In recent years, industry-wide demand growth exceeded supply growth for certain surface mining equipment and off-the-road tires. As a result, lead times for some items generally increased to several months and prices for these items 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 financial 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 commodities or assets 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.

Derivatives regulations included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, Dodd-Frank was passed by Congress and signed into law. Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as "margin") for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Dodd-Frank requires the CFTC to promulgate rules to define these terms, however we do not yet know the rules that the CFTC will actually promulgate or whether the rules or exceptions thereto will apply to us.

We use crude oil and natural gas derivative instruments in conjunction with our Energy Marketing activities and to hedge the sales price for a portion of our expected oil and gas production. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. Depending on the regulations adopted by the CFTC, we could be required to post additional collateral with our dealer counterparties for our commitments and interest rate derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

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 potential adverse effects resulting from changes in 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 they are closely 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, coal 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.

We may be adversely affected if we fail to achieve or maintain compliance with existing or future governmental 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 regulations, 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 or cause us to reevaluate the feasibility of continued operations at certain sites, 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.

Our energy marketing segment may be subject to increased regulation.

In January 2010, the CFTC proposed regulations aimed at establishing speculative position limits on energy commodities. The proposed regulations would apply to all CFTC-regulated exchanges and would cap the number of contracts a market participant can hold at the NYMEX or Intercontinental Exchange. The position limit would restrict the amount of contracts a market participant can hold at any one time. This proposal is intended to curb excessive speculation in the energy markets and is part of a wider push to overhaul the financial markets. Due to uncertainty as to the final outcome of any rulemaking or legislation, we cannot definitively estimate the effect of increased regulation on our results of operations, cash flows or financial position.

Our financial performance depends on the successful operations of our facilities.

Operating electric generating facilities, the coal mine and electric and natural gas distribution systems involves risks, including:

- Operational limitations imposed by environmental and other regulatory requirements.
- Interruptions to supply of fuel and other commodities used in generation and distribution. The Gas Utilities purchase fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather, and environmental regulations which could limit the Gas Utilities' ability to operate their facilities.
- Breakdown or failure of equipment or processes.
- Inability to recruit and retain skilled technical labor.
- Labor relations. Approximately 33% of our employees are represented by a total of six collective bargaining agreements. We are currently in contract renewal negotiations on two of these agreements. Three separate arbitration proceedings have been initiated by the respective union locals concerning changes we made to our pension plans.
- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered.
- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence.

We may be vulnerable to cyber attacks and terrorism.

Man-made problems such as computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products.

Federal and state laws concerning greenhouse gas regulations and air emissions 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, and Colorado. We recently completed another fossil-fuel generating plant in Wyoming and are constructing others in Colorado. Recent developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants will likely result in more stringent emission limitations, which could have a material impact on our costs or operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the caption "Environmental Matters."

On April 29, 2010, the EPA published proposed Industrial and Commercial Boiler regulations, which provide for hazardous air pollutant-related emission limits and monitoring requirements for both major and area sources of hazardous air pollutants. The final rule has a court-ordered deadline of February 21, 2011 and we will evaluate once final. If issued as proposed, will have significant impact at our Neil Simpson I, Osage, Ben French and W.N. Clark facilities. The regulation currently has a three year compliance window and will require an engineering evaluation to determine economic viability of continued operations at these units. We currently expect that, the adoption of these regulations will lead to retirement of these units within three years of the effective date of the final rule.

The EPA is obligated under a court-approved consent decree to sign a proposed electric utility hazardous air pollutant rule (Utility MACT rule) by March 16, 2011 and sign its notice of final rulemaking by November 16, 2011. We expect that affected units will have three years from effective date to be in compliance with the new rules. In 2010, we participated in the EPA's efforts to gather data for rule development. Certain requirements of that regulation could have significant impacts on the Neil Simpson II, Wygen I, Wygen II, Wygen III and Wyodak facilities.

On June 23, 2010, the EPA published in the Federal Register the GHG Tailoring Rule, implementing regulations of GHG for permitting purposes. This rule will impact us in the event of a major modification at an existing facility or in the event of a new major source. Existing permitted facilities will see monitoring reporting requirements incorporated into their operating permits upon renewal. New projects or major modifications to existing projects will result in a Best Available Control Technology review that could result in more stringent emissions control practices and technologies.

In 2010, the State of Colorado enacted House Bill 1365, the Colorado Clean Air, Clean Jobs Act, a coordinated utility plan to reduce air emissions from coal fired power plants and promoting the use of natural gas and other low emitting resources. This act has a significant impact on our W.N. Clark facility and on October 29, 2010, Colorado Electric filed testimony with the CPUC that recommended retirement of the W.N. Clark facility to comply with House Bill 1365 within three years of promulgation of the EPA's proposed Industrial and Commercial Boiler Hazardous Air Pollutant Regulations, or in the absence of such regulation, to retire the units by the end of 2017. On December 16, 2010, the CPUC issued an order approving the closure of the W.N. Clark generation facility by December 31, 2013, and granted a presumption of need for replacement of the plant. Colorado Electric proposed to construct a third 92 MW General Electric LMS100 natural gas-fired turbine at its Pueblo Airport Generation Station. Colorado Electric will file a Certificate of Public Convenience and Necessity in the first quarter of 2011 that will provide additional justification for the incremental 50 MW generation capacity.

Due to uncertainty as to the final outcome of federal climate change legislation, or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG regulation on our results of operations, cash flows or financial position. The impact of GHG legislation or regulation upon our company will depend upon many factors, including but not limited to the timing of implementation, the GHG sources that are regulated, the overall GHG emissions cap level, and the availability of technologies to control or reduce GHG emissions. If a "cap and trade" structure is implemented, the impact will also be affected by the degree to which offsets are allowed, the allocation of emission allowances to specific sources, and the effect of carbon regulation on natural gas and coal prices.

New or more stringent regulations or other energy efficiency 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, the acquisition or development of additional energy supply from renewable resources, 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.

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.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization. As a result, coal users may switch to other fuels, which could affect the volume of our sales and the price of our products.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine, carbon and other elements or compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fueled power plants could increase the costs of using coal thereby reducing demand for coal as a fuel source and the volume and price of our coal sales. Stricter regulations could make coal a less attractive fuel alternative in the planning and building of power plants in the future.

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter, or greenhouse gases may require the installation of costly emission control technology or the implementation of other measures. For example, in order to meet the federal Clean Air Act limits for SO_2 emission from power plants, coal users may need to install scrubbers, use SO_2 emission allowances (some of which they may purchase), blend high-sulfur coal with low-sulfur coal or switch to other fuels. Reductions in mercury emission required by certain states will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury. Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

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.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The Energy Policy Act of 2005 increased FERC's civil penalty authority for violation of FERC statutes, rules and orders. FERC may now impose penalties of $1.0 million per violation, per day. The CFTC, EPA, OSHA and MSHA also impose civil penalties to enforce compliance requirements relative to our business. In addition, FERC has delegated certain aspects of authority for enforcement of electric system reliability standards to the NERC, with similar penalty authority for violations. If a serious regulatory violation did occur, and penalties were imposed by FERC or another federal agency, this action 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:

- Energy Policy Act of 2005 and the repeal of the PUHCA;
- Industry consolidation;
- Consumer demands;
- Transmission constraints;
- Renewable resource supply requirements;
- Resistance to the siting of utility infrastructure or to the granting of right-of-ways;
- 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. 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 adversely affect our financial condition or results of operations.

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.

The recent global financial crisis made the credit markets less accessible and created a shortage of available credit. Should a similar financial crisis occur in the future, we may 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.

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 then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

FORM 10K

The global financial crisis has affected 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.

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 quality and adjust the credit limits based upon such changes, our credit guidelines, controls and limits may not fully protect us from increasing counterparty credit risk. To the extent the economic conditions 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.

The continued recessionary environment and any future recession may lead to an increase in late payments from retail, commercial and industrial 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.

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. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt 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.

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, Nebraska, Wyoming, South Dakota and Montana. In connection with the Aquila Transaction, the settlement agreements or acquisition orders approved by the CPUC, IUB, KCC and NPSC 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.

We expect to continue our policy of paying regular cash dividends. However, there is no assurance as to the amount of future dividends because they depend on our future earnings, capital requirements, and financial conditions, and are subject to declaration by the Board of Directors. Our operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to us. See "Liquidity and Capital Resources" within Management's Discussion and Analysis in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

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 certain 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.

Increasing costs associated with our 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.

In March 2010, the President of the United States signed PPACA as amended by the Health Care and Education Reconciliation Act of 2010 (collectively the “2010 Acts”). The 2010 Acts will have a substantial impact on health care providers, insurers, employers and individuals. The 2010 Acts will impact employers and businesses differently depending on the size of the organization and the specific impacts on a company’s employees. Certain provisions of the 2010 Acts became effective during our open enrollment period (November 1, 2010) while other provisions of the 2010 Acts will be effective in future years. Although the constitutional validity of the 2010 Acts is the subject of numerous lawsuits now pending in the federal courts, the outcome of which is uncertain, the 2010 Acts could require, among other things, changes to our current employee benefit plans and in our administrative and accounting processes. The ultimate extent and cost of these changes cannot be determined at this time and are being evaluated and updated as related regulations and interpretations of the 2010 Acts become available, and as the results of pending litigation become final.

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 registered public accounting firm 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 related to these utilities would cause a decrease in our assets and a reduction in our net income and shareholders' equity.

We had approximately $354.8 million of goodwill on our consolidated balance sheet as of December 31, 2010. 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 a non-cash impairment charge, which would reduce our reported assets and 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 19, "Commitments and Contingencies", of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. SPECIALIZED DISCLOSURES (UNDER PROPOSED RULES)

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 99.1 of this Annual Report.

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, 2010, we had 4,667 common shareholders of record and approximately 24,000 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 27, 2011 meeting, our Board of Directors declared a quarterly dividend of $0.365 per share, equivalent to an annual dividend of $1.46 per share, marking 2011 as the 41st 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 in this Annual Report on Form 10-K."

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, 2010

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Common stock prices				
High	$ 30.83	$ 34.49	$ 33.31	$ 33.42
Low	$ 25.65	$ 27.34	$ 27.79	$ 29.32

Year ended December 31, 2009

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.355	$ 0.355	$ 0.355	$ 0.355
Common stock prices				
High	$ 27.84	$ 23.45	$ 26.90	$ 27.98
Low	$ 14.63	$ 17.36	$ 22.57	$ 23.16

UNREGISTERED SECURITIES ISSUED DURING 2010

There were no unregistered securities sold during 2010, 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, 2010 – October 31, 2010	—	$ —	—	—
November 1, 2010 – November 30, 2010	761	$ 32.42	—	—
December 1, 2010 – December 31, 2010	3,222	$ 30.75	—	—
Total	3,983	$ 31.07	—	—

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

FORM 10K

ITEM 6. SELECTED FINANCIAL DATA

Years Ended December 31, (dollars in thousands, except per share amounts)	2010	2009	2008 (1)	2007	2006
Total Assets	$ 3,711,509	$ 3,317,698	$ 3,379,889	$ 2,469,634	$ 2,241,798
Property, Plant and Equipment					
Total property, plant and equipment	$ 3,359,762	$ 2,975,993	$ 2,705,492	$ 1,847,435	$ 1,661,028
Accumulated depreciation and depletion	(864,329)	(815,263)	(683,332)	(509,187)	(462,557)
Capital Expenditures	$ 496,990	$ 347,819	$ 1,304,352 (2)	$ 267,047	$ 308,450
Capitalization					
Current maturities	$ 5,181	$ 35,245	$ 2,078	$ 130,326	$ 4,249
Notes payable	249,000	164,500	703,800	37,000	145,500
Long-term debt, net of current maturities	1,186,050	1,015,912	501,252	503,301	554,411
Common stock equity	1,100,270	1,084,837	1,050,536	969,855	790,041
Total capitalization	$ 2,540,501	$ 2,300,494	$ 2,257,666	$ 1,640,482	$ 1,494,201
Capitalization Ratios					
Short-term debt, including current maturities	10.0%	8.7%	31.3%	10.2%	10.0%
Long-term debt, net of current maturities	46.7%	44.2%	22.2%	30.7%	37.1%
Common stock equity	43.3%	47.1%	46.5%	59.1%	52.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Total Operating Revenues	$ 1,307,251	$ 1,269,578	$ 1,005,790	$ 574,838	$ 542,585
Net Income Available for Common Stock					
Utilities	$ 74,563	$ 57,071	$ 43,904	$ 31,633	$ 24,188
Non-regulated Energy	13,616	579 (4)	(23,345) (5)	49,897	37,098
Corporate expenses and intersegment eliminations	(19,494) (3)	21,106 (3)	(72,596) (3)	(5,872)	(5,514)
Income (Loss) from Continuing Operations	68,685	78,756	(52,037)	75,658	55,772
Discontinued operations[6]	—	2,799	157,247	23,491	25,757
Net loss attributable to non-controlling interest	—	—	(130)	(377)	(510)
Net income available for common stock	$ 68,685	$ 81,555	$ 105,080	$ 98,772	$ 81,019
Dividends Paid on Common Stock	$ 56,467	$ 55,151	$ 53,663	$ 50,300	$ 43,960
Common Stock Data[7] (in thousands)					
Shares outstanding, average	38,916	38,614	38,193	37,024	33,179
Shares outstanding, average diluted	39,091	38,684	38,193	37,414	33,549
Shares outstanding, end of year	39,269	38,969	38,636	37,796	33,369
Earnings (Loss) Per Share of Common Stock (in dollars) [7]					
Basic earnings (loss) per average share -					
Continuing operations	$ 1.76	$ 2.04	$ (1.37)	$ 2.04	$ 1.68
Discontinued operations	—	0.07	4.12	0.63	0.77
Non-controlling interest	—	—	—	(0.01)	(0.01)
Total	$ 1.76	$ 2.11	$ 2.75	$ 2.66	$ 2.44
Diluted earnings (loss) per average share -					
Continuing operations	$ 1.76	$ 2.04	$ (1.37)	$ 2.02	$ 1.66
Discontinued operations	—	0.07	4.12	0.63	0.77
Non-controlling interest	—	—	—	(0.01)	(0.01)
Total	$ 1.76	$ 2.11	$ 2.75	$ 2.64	$ 2.42
Dividends Declared per Share	$ 1.44	$ 1.42	$ 1.40	$ 1.37	$ 1.32

Years ended December 31,	2010	2009	2008	2007	2006
Book Value Per Share, End of Year	$ 28.02	$ 27.84	$ 27.19	$ 25.66	$ 23.68
Return on Avg Common Equity (year-end)	6.3 %	7.6 %	10.4 %	11.2 %	10.6 %
Operating Statistics:					
Generating capacity (MW):					
Utilities (owned generation)	687	630	630	435	435
Utilities (purchased capacity)	440	430	420	50	50
Independent power generation(8)	120	120	141	983	989
Total generating capacity	1,247	1,180	1,191	1,468	1,474
Electric Utilities:					
MWh sold:(1)					
Retail electric	4,532,191	4,403,459	3,532,402	2,636,425	2,552,290
Contracted wholesale	468,782	645,297	665,795	652,931	647,444
Wholesale off-system	1,749,524	1,692,191	1,551,273	678,581	942,045
Total MWh sold	6,750,497	6,740,947	5,749,470	3,967,937	4,141,779
Gas Utilities:(1) (9)					
Gas sold (Dth)	55,265,630	56,671,438	23,053,599	—	—
Transport volumes (Dth)	59,879,450	55,104,284	26,805,075	—	—
Oil and gas production sold (MMcfe)	11,300	12,463	13,534	14,627	14,414
Oil and gas reserves (MMcfe)	131,096	119,304	185,542	207,806	199,092
Tons of coal sold (thousands of tons)	5,931	5,955	6,017	5,049	4,717
Coal reserves (thousands of tons)	261,860	268,000	274,000	280,000	285,000
Average daily marketing volumes:					
Natural gas physical sales (MMBtu)	1,586,000	1,974,300	1,873,400	1,743,500	1,598,200
Crude oil physical sales (Bbls)	18,455	12,400	7,880	8,600	8,800
Coal physical sales (Tons)(10)	33,250	—	—	—	—

(1) Includes electric and gas utilities acquired on July 14, 2008.
(2) Includes $938.4 million for the Aquila acquisition.
(3) 2010 and 2008 includes a $9.9 million and a $61.4 million after-tax unrealized mark-to-market loss related to certain interest rate swaps; while 2009 includes a $36.2 million after-tax unrealized mark-to-market gain related to certain interest rate swaps.
(4) Includes a $27.8 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2009 and a $16.9 million after-tax gain on sale of 23.5% ownership interest in Wygen I.
(5) Includes a $59.0 million after-tax ceiling test impairment charge to our crude oil and natural gas properties taken in 2008.
(6) 2009, 2008, 2007 and 2006 include the operations of the assets sold in the IPP Transaction.
(7) During February 2007, we issued 4.2 million shares of common stock, which dilutes our earnings per share in subsequent periods.
(8) 2007 and 2006 include 825 MW which have been reported as "Discontinued operations."
(9) Excludes Cheyenne Light.
(10) Represents coal marketing operations which began June, 2010.

Certain items related to 2007 and 2006 have been restated from prior year presentation to reflect the classification of the 2008 IPP Transaction as discontinued operations and non-controlling interest (see Notes 1 and 22 of the Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K).

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 17 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 201,000 customers in South Dakota, Wyoming, Colorado and Montana and includes the operations of Cheyenne Light and its approximately 34,500 gas utility customers in Wyoming. Our Gas Utilities segment serves approximately 527,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group engages in the production of coal, natural gas, crude oil and coal; the production of electric power through ownership of a portfolio of generating plants and the sale of electric power and capacity primarily under mid- and long-term wholesale contracts; and in the marketing of natural gas, crude oil, coal, power and environmental products and related services primarily in the United States and Canada.

Industry Overview

The United States energy industry experienced another tumultuous year in 2010. The global economic crisis that commenced in late 2008, and continued through 2010, reduced energy demand. Energy commodity prices, which were near historic highs in mid-2008, experienced dramatic declines in early 2009. While crude oil prices recovered notably through 2009 and in 2010, natural gas prices have remained low. Domestic crude oil prices continued to be influenced by global factors, including foreign economic conditions (especially in China and Asia), the policies of OPEC and other large foreign oil producers, and political tensions and conflict in many regions.

However, the proliferation of domestic natural gas shale plays in recent years has provided the market an abundant new supply of natural gas. Combined with demand destruction from the economic downturn, this new and abundant supply source has created record volumes of natural gas in storage, and reduced domestic natural gas prices. In fact, the ratio of crude oil to natural gas prices is at all time highs, far in excess of the six to one heating value equivalent ratio. This trend is likely to continue for the foreseeable future given the expected further development of domestic shale gas reserves.

Coal prices have also been volatile during the past year. Powder River Basin Spot prices (8800 Btu per pound) were $6.61 per ton in late 2009, but have been quite volatile during 2010, trading as high as $14.84 per ton. Toward the end of 2010, pricing pulled back and Power River Basin coal was trading around $13.00 per ton.

Like other United States industries, the energy industry is faced with numerous uncertainties, both short and long-term. Many utilities have 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 the prolonged, severe recession has affected the demand for energy and the ability of customers to pay their utility bills, particularly in certain parts of the country. The recession also impacted the ability of companies to obtain the capital necessary for infrastructure expansion. In 2010, the United States economy appears to have initiated a slow recovery from the deep recession. For credit-worthy companies, equity and debt financings were successfully undertaken throughout 2010.

The state utility regulatory climate in 2010 remained relatively constructive among government, industry and consumer representatives. In the seven-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. Challenges remain, however, in obtaining satisfactory rate recovery for utility investments due to the general state of the economy and concern by regulators in various states that utility rate increases may cause further harm to local economies.

At the federal level, the passage of a major economic stimulus package by Congress in 2009, and the bailout of several "too large to fail" financial firms and automobile manufacturers, set the stage for an emphasis on increased regulation and government oversight of industry, which continued into 2010. In addition, in late 2009, Congress focused on the passage of major healthcare reform legislation. The EPA is likely to pass rules in 2011 that will likely require the potential closure of many older coal burning power plants. State legislatures also remained active on environmental issues in 2010, with a majority of states now having adopted some form of renewable energy standard, including some in which we operate. In addition, several states have passed greenhouse gas emissions legislation, which places limits on the emissions of CO_2 and other greenhouse gases. These known and potential legislative actions could have significant macroeconomic consequences, as the associated cost increases may cause a dramatic increase in consumer costs for products and services, including rates for electricity and other energy in the mid- to long-term.

The November 2010 elections caused a significant change in the domestic political environment, and a dramatic shift in domestic policy. The passage in December of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, extends through 2012 lower tax rates introduced in 2001 and 2003, reduces the estate tax, extends unemployment benefits, reduces the Social Security portion of payroll taxes for employees, and extends bonus depreciation. A benefit to our investors, the bill extends through 2012 the lower capital gains tax rate introduced by the Jobs and Growth Tax Relief Reconciliation Act of 2003. Additionally, the bill extends the 100% bonus depreciation for business property acquired after September 8, 2010 and placed into service prior to January 1, 2012. This provision will provide positive tax benefits for the Colorado Electric and Colorado IPP generation projects currently under construction.

The energy marketplace continues to respond to the increased oversight and enforcement activity of 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 decade, the corporate structure of many energy companies underwent evaluation and change, in large part due to efforts to create additional shareholder value. Since before the economic crisis, a number of companies contemplated or implemented a realignment of business lines, reflecting a shift in long-term strategies. Some divested certain energy properties to focus on core businesses, such as exiting non-regulated power production, or energy marketing in favor of more stable utility operations. Others engaged in mergers and acquisitions with a goal to improve economies of scale and returns to investors. While mergers and acquisition activity in the utility industry essentially stopped during much of the past two years, several transactions have been announced in late 2010 and early 2011 which may signal a resumption of utility transactions. Private equity investors continued to play a role in the changing composition of energy ownership.

Many industry analysts cite the need for expanded energy capacity and delivery systems. They continue to 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 willing to provide acceptable rate treatment for additional utility investment, although the current state of the economy makes rate recovery more challenging in the short run. Oil and gas producers will continue to explore for new reserves, particularly natural gas, which will be the primary fuel of choice in light of concern regarding GHG emissions and the need to provide backup generation for renewable energy resources. The growing focus on environmental regulation made it increasingly more difficult to obtain drilling permits, particularly on public and Native American lands. However, current low natural gas prices prompted some companies to curtail projects in order to conserve cash during a period of low cash flow and constrained capital markets.

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. Several years ago, the State of California mandated that future imports of power must come from power plants with emission levels no greater than combined-cycle natural gas-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, voluntarily and in response to regulatory mandates. Emissions from new coal-fired plants are now a small fraction of those produced by power plants built a generation ago. 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 DOE 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 industrial and retail energy 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 cost effectively, and to achieve suitable returns on investment.

We believe that we are well-positioned in this industry setting, and able to proceed with our key business objectives. Along with industry counterparts, we are preparing to address the challenges discussed in this overview, such as new environmental regulations and mandates, renewable portfolio standards, CO_2-related taxes or trading practices, 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 the production of crude oil, natural gas and coal, and the marketing of natural gas, crude oil, coal, power and environmental products. Our focus on customers - whether they are utility customers or non-regulated generation, fuel or marketing customers - provides opportunities to expand our businesses by constructing additional rate base assets to serve our utility customers and expand our non-regulated energy holdings to provide additional products and services to our wholesale customers.

The diversity of our energy operations reduces reliance on any single business segment to achieve our strategic objectives. It mitigates our overall corporate risk and enhances our ability to earn stronger returns for shareholders over the long-term. Despite challenging conditions in the capital markets over the past few years, we have demonstrated our ability to access the debt and equity markets, resulting in sufficient liquidity and solid cash flows. Consequently, our financial foundation is sound and capable of supporting an expansion of operations in both the near and long-term.

During 2010, we focused on completing the integration of the five utility properties acquired from Aquila in mid-2008 and the achievement of certain operating efficiencies made possible by the acquisition. During 2010 we built upon the successful 2009 consolidation of our customer information system by unifying our employee pay and benefits programs and completing substantially all of our major systems consolidations, including our human resource and financial systems, GIS mapping system, work management system and SCADA system.

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 significantly grow our asset base to serve projected customer demand and to comply with environmental mandates in our existing utility service territories through expansion of infrastructure and 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 appropriate rate recovery to provide solid economic returns on our utility investments.

We will continue to prudently grow and develop our existing inventory of oil and gas reserves, while we strive to maintain strong relationships with mineral owners, landowners and regulatory authorities. We intend to focus our near-term efforts on proving up the shale gas potential of our San Juan and Piceance Basin properties, while continuing our participation in the Bakken oil shale play and other oil-related exploration opportunities. Given increased regulatory emphasis on wind and solar power generation, and potential environmental regulations and 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 required to provide critical back-up supplies 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. We also intend to utilize the newly acquired coal marketing expertise within our energy marketing operations to develop additional rail-served sales opportunities for our coal. Nearly 50% of all electricity generated in the United States is currently supplied from coal-fired power plants. It will take decades and significant expense 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 are investigating the possible deployment of these technologies at our mine site in Wyoming.

We have expertise in permitting, constructing and operating power generation facilities. These skills, combined with our understanding of electric resource planning and regulatory procedures, provide a significant opportunity for us 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 long-term profitability through a risk-managed and disciplined approach to the marketing of natural gas, crude oil, coal, power and environmental products. We will continue to utilize our marketing expertise to enhance the value of our other energy assets, particularly our fuel and power generation assets. During 2010, in an effort to lessen the dependence of our energy marketing earnings on natural gas, we added coal, power and environmental products to our marketing portfolio.

Key Elements of our Business Strategy

- 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 mitigating and remaining mindful of 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 regional 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;
- Increase the value of our oil and gas properties by prudently growing our reserves and increasing our production of natural gas and crude oil;
- Expand our energy marketing operations opportunistically in the area of natural gas, crude oil, coal, power and environmental products as market conditions warrant;
- 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.

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 began as a vertically integrated electric utility, and this business model remains a core strength and strategy today, as we invest in and operate efficient power generation resources to cost effectively 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-base generation assets offer several advantages for consumers, regulators and investors. First, since the generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable than if the power was purchased from the open market through wholesale contracts that are renegotiated over time. 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 April 2010 completion of Wygen III to serve the customers of Black Hills Power. During 2009, our Colorado Electric subsidiary completed a comprehensive resource planning process, through which we received approval to construct a 180 MW gas-fired power plant as a rate base asset to serve the customers of Colorado Electric. Construction commenced on this facility in July 2010 and its projected commercial operation date is December 31, 2011. Existing legislation in Colorado will require the retirement of Colorado Electric's W.N. Clark plant by December 31, 2013. Pending EPA regulations covering hazardous air pollutants may necessitate the early retirement of several of our older coal-fired power plants, including Black Hills Power's Osage, Ben French and Neil Simpson I plants and Colorado Electric's W.N. Clark plant. Although we are still evaluating alternatives, it is likely that we will recommend replacing these facilities with rate-based natural gas fired power plants.

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 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

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2008) and our Wygen III generation facility (completed in April 2010). Constructing these state-of-the-art, cost-efficient, coal-fired facilities allows us to plan for the future retirement of older, less efficient plants with higher emissions and keep rates reasonable for customers. 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 regulatory or legislative actions place a sufficiently high price on CO_2 emissions or further technological advancements reduce the costs of those technologies. The location of our coal mine and power plant complex in the Powder River Basin of Wyoming provides key strategic advantages for carbon capture and sequestration projects, such as readily available saline aquifers for the injection and sequestration of CO_2, as well as a potential CO_2 market for use in enhanced oil recovery projects. Additionally, the Wyoming legislature has been proactive in passing legislation to address pore space ownership, injection regulations and other legal issues associated with the underground sequestration of CO_2.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating and remaining mindful of customer rate impacts. The energy and utility industries face tremendous uncertainty related to the potential impact of legislation and regulation intended to reduce GHG 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 GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions is also under consideration.

Mandates for the use of renewable energy or the reduction of GHG emissions will likely produce 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 GHG emission reductions that balances our customers' rate concerns with environmental considerations and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers. Examples of our balanced approach include:

- In states such as South Dakota and Wyoming that currently have no legislative mandate on the use of renewable energy, we have proactively integrated cost-effective renewable energy into our generation supply based upon our expectation that there will be mandatory renewable energy standards in the future. For example, under two 20-year PPAs we purchase a total of 60 MW of wind energy from wind farms located near Cheyenne, Wyoming for use at Black Hills Power and Cheyenne Light;
- Colorado and Montana have legislative mandates regarding the use of renewable energy, therefore we aggressively pursue cost-effective initiatives with the regulators that will allow us to meet our renewable energy requirements. In Colorado for instance, we filed an electric resource plan that includes enough renewable energy additions and GHG emission reductions to permit us to satisfy the State's requirement that 30% of a utility's distributed energy must be supplied by renewable energy resources by 2020. To the extent practical, we intend to construct renewable generation resources as rate base assets, which will help mitigate the long-term customer rate impact of adding renewable energy supplies; and
- In all states in which we conduct electric utility operations, we are exploring other potential biomass, solar and wind energy projects, particularly wind generation sites located near our utility service territories.

Expand utility operations through selective acquisitions of electric and gas utilities consistent with our regional focus and strategic advantages. For nearly 128 years we have provided reliable 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 areas 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.

Through our recently completed integration of the utilities we acquired in mid-2008, we have a platform of systems and processes which are very scalable, which would simplify the integration of potential future utility acquisitions. Although we do not expect to make any significant utility acquisitions in the near term, merger and acquisition activity has increased in recent months. We believe that impacts of the current 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 continue to need products, such as capacity, in order to reliably serve their customers. 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, are now also joint owners in two of our power plants, Wygen I and Wygen III, respectively.

Selectively grow our non-regulated power generation business in targeted regional 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 mid-2008, we divested 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 the development of new power generation facilities and disciplined acquisitions primarily in the western region where our detailed knowledge of market and electric transmission fundamentals provides us a competitive advantage, and, consequently increases our ability to earn attractive returns. We expect to prioritize small-scale facilities that serve incremental growth or provide critical back up to renewable resources, and are typically 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. 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 non-regulated capacity and energy primarily to load-serving utilities under long-term agreements that have been reviewed or approved by state utility commissions. An example of this strategy is the 200 MW of combined-cycle gas-fired generation being constructed by our non-regulated power generation subsidiary to serve our Colorado Electric utility subsidiary beginning January 1, 2012, under a 20-year tolling agreement.

With respect to our current power sale agreements, two of our long-term power contracts provide for the sale of capacity and energy to Cheyenne Light from our Gillette CT and Wygen I plants. The Gillette CT contract expires in 2011, and as part of our integrated resource planning efforts, the company is evaluating a potential extension of the contract. The Wygen I contract was extended during 2009 and now expires in 2022, but provides an option for Cheyenne Light to purchase and rate base a portion of Wygen I.

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 leverage this competitive advantage by building additional state-of-the-art 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.

Increase the value of our oil and gas properties by prudently growing our reserves and increasing our production of natural gas and crude oil. 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 creation over managing for growth as follows:

- Through detailed reservoir analysis, apply proven technologies to our existing assets to maximize value;
- Participate in a limited number of selective and meaningful exploration prospects;
- Primarily focus on the Rocky Mountain region, where we can more easily integrate new opportunities with our existing oil and natural gas operations as well as our fuel marketing and/or power generation activities. Specifically, we intend to focus our near term efforts on fully evaluating the shale gas potential of our San Juan and Piceance Basin properties, continuing

our participation in the Bakken oil shale play and participating in select oil exploration prospects with substantial upside opportunities;

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

Expand our energy marketing operations opportunistically in the area of natural gas, crude oil, coal, power and environmental products as market conditions warrant. Our energy marketing business seeks to provide services to producers and end-users of natural gas, crude oil, coal, power and environmental products and to capitalize on market volatility by employing certain risk-managed commodity trading strategies. The diversity of the commodities portfolio that we market helps us optimize value for shareholders. 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 independent 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. Our coal marketing team assists small utility and industrial coal consumers manage their coal procurement and transportation functions. Similarly, our power marketing experts helps both buyers and sellers of electricity, as well as assisting customers with the monetization of emissions or other environmental products.

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 diverse 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 implemented risk management policies and procedures, particularly for our marketing operations. Our oversight committees monitor compliance with these policies. We also limit exposure to energy marketing risks by maintaining an energy marketing credit facility separate from our corporate credit facility.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. Access to capital has been and will continue to be critical to our 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. Our access to adequate and cost-effective financing depends upon our ability to maintain our investment grade issuer credit rating.

Disruption in worldwide capital markets over the past few years has reduced liquidity in the debt capital markets and caused 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 government, these events contributed to a general economic decline that materially and adversely impacted the broader financial and credit markets, and reduced the availability of debt and equity capital, particularly in late 2008 and 2009. Our acquisition of additional utility properties in 2008, combined with the divestiture of seven IPP plants, reduced our overall corporate risk profile. Even so, our access to capital markets was negatively impacted by the conditions described above, particularly during the fourth quarter of 2008 and the first quarter of 2009.

Notwithstanding these adverse market conditions, in addition to several financings during 2009, in 2010 we completed additional key financings on reasonable terms, including a net $125.1 million equity offering, a $200 million senior unsecured corporate bond offering, a $100 million term loan, and renewal of our Revolving Credit Facility.

Prospective Information

We expect to generate long-term growth through the expansion of integrated and diverse energy operations. We recognize that sustained growth requires continued capital deployment. Our diversified energy portfolio with an emphasis on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from major capital investments at our existing segments. As capital market conditions improved in 2010, we were able to complete several key debt and equity financings. We are confident in our ability to obtain additional financing to continue our growth plans. 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 execute our long-term strategic plan.

Utilities Group

The Utilities Group successfully completed four rate cases in 2010 and completed integration activities subsequent to the Aquila Transaction which establishes a growth platform that delivers value to our shareholders. During 2010, the Utilities Group unified the GIS mapping system and integrated the SCADA systems and along with our Non-Regulated group, completed conversion to a single human resources, inventory management and accounting system.

Electric Utilities

We benefited from an increase in rates resulting from three rate cases. An approved revenue increase of $15.2 million went into effect April 1, 2010 for South Dakota customers, an approved annual revenue increase of $3.1 million went into effect June 1, 2010 for Wyoming customers, and an approved annual revenue increase of $17.9 million went into effect on August 6, 2010 for our Colorado Electric customers. Included in the Colorado Electric rate case order was a provision that off-system sales margins be shared with customers commencing August 6, 2010. The percentage of margin to be shared with the customers was not resolved at the time of the rate case settlement. The CPUC has therefore required that the off-system sales margins earned beginning August 6, 2010 be deferred on the balance sheet until settlement of the sharing mechanism. Colorado Electric is preparing a proposal for a sharing mechanism to be filed with the CPUC.

Business at Black Hills Power remained relatively strong in 2010. Construction of the Wygen III power plant was completed and the plant commenced commercial operation on April 1, 2010. A 23% ownership interest in the Wygen III plant was sold to the City of Gillette for $62.0 million. Black Hills Power now owns 52% of the facility with the City of Gillette owning 23% and MDU owning the remaining 25%.

We continue to focus on Colorado Electric's Energy Resource Plan. In July 2010, construction commenced on a 180 MW gas-fired generation facility that will serve Colorado Electric customers upon expiration of the current PPA with PSCo. Construction is expected to cost between $250 million and $260 million and commercial operations are expected to begin by January 1, 2012. The addition of these plants to our utility rate base and a successful approval of our proposed rate case will have a significant positive impact on our financial results. We plan to file a rate case that anticipates the inclusion of new generation and transmission assets in customer rates beginning upon the commencement of commercial operation of the plants.

In December 2010, Colorado Electric received a final order from the CPUC which approved the retirement of its W.N. Clark coal-fired generation facility by December 31, 2013 and granted a presumption of need in the amount of 42 MW for replacement of the plant with gas-fired generation. Colorado Electric will file a Certificate of Public Convenience and Necessity to provide justification for an additional 50 MW of generating capacity to allow the construction of a 92 MW natural gas-fired facility.

The expiration and replacement of the PSCo contract at Colorado Electric requires additional capacity and energy needs of approximately 200 MW. The remaining capacity and energy needed was acquired through a competitive bidding process including other power producers. Our Power Generation segment participated in this bidding process, and in September 2009, our Power Generation segment was awarded the bid to provide 200 MW of capacity and energy to Colorado Electric through a 20-year PPA.

Our Electric Utilities are receiving funding available through the American Recovery and Reinvestment Act of 2009 to install 149,000 smart meters. We have completed 100% of the installations and expect to have expended all grant funds by the end of 2011.

Gas Utilities

Our Gas Utilities are focused on the continued investment in our gas distribution network and related technology such as automated meter reading and mobile data terminals. We received approval for rate increases of $8.3 million at Nebraska Gas and filed a rate request for an increase in revenues of $4.7 million at Iowa Gas. In August 2010, we reached a settlement with the OCA for a revenue increase at Iowa Gas of $3.4 million. This settlement agreement was modified and re-filed on January 11, 2011. The modified settlement excludes the integrity investment tracker and the three-year rate moratorium included in the original settlement agreement filed on September 1, 2010, which was not approved by the IUB. Approval of the modified settlement was received from the IUB on February 10, 2011. We continually monitor our investments and costs of operations in all states to determine when additional rate case or other rate filings will be necessary.

Non-regulated Energy Group

Power Generation

Our Power Generation segment was awarded the bid to provide 200 MW of power to our Colorado Electric subsidiary through a 20-year PPA. Construction of two 100 MW combined cycle natural gas-fired power generation facilities in Colorado commenced in July 2010. Construction is expected to cost between $250 million and $260 million and commercial operations are expected to commence prior to December 31, 2011.

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

Coal Mining

Production from the Coal Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production is estimated to be approximately 6.5 million tons in 2011. 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. We have recently extended two smaller volume off-site sales contracts and anticipate continued off-site sales to PacifiCorp's Dave Johnson power plant through a contract which expires at the end of 2011. There are some limitations in regards to transporting our lower-heat content coal, but we are reviewing new opportunities to market our coal.

Oil and Gas

During 2010 we initiated a review of our oil and gas strategy and assets that will continue until at least mid-2011. BHEP's mission in 2010 was to identify future investment opportunities while conserving capital and strictly controlling costs. This task will continue into 2011, in anticipation of providing attractive oil and gas investment opportunities as more capital becomes available following completion and commissioning of the plants under construction by Colorado Electric and Colorado IPP.

Energy Marketing

We have a marketing portfolio with a significant amount of optionality that can provide opportunities to create economic value over the next several years. While we expect to derive earnings from these contracts over many years, market conditions and the required methods of accounting for these transactions could result in additional earnings volatility during the term of these contracts.

During 2009 and continuing into 2010, there was a significant contraction in the availability of capital. Despite these challenges, we entered into a two year committed Enserco Credit Facility on May 8, 2010.

In June 2010, our Energy Marketing segment expanded the commodities it markets to include coal through an acquisition of a coal marketing business for $2.25 million and the addition of six new employees. The business focuses on sourcing coal from Wyoming's Powder River Basin for delivery to customers in the western United States. Our average daily marketing physical volumes since the acquisition were approximately 33,250 tons of coal. In the fourth quarter of 2010, our Energy Marketing segment expanded into power and environmental marketing through the addition of four experienced employees.

Corporate

During 2010, we completed two long-term financings including a $200.0 million senior unsecured bond offering which is being used to fund construction of generation facilities to serve our Colorado Electric customers and a forward equity offering of 4,413,519 shares. We also entered into a new $500 million Revolving Credit Facility and a $100 million term loan to fund our working capital needs and for other corporate purposes.

We have substantially completed the integration of processes and systems resulting from our acquisition of five utility properties in mid-2008. The unified systems and processes provide us with a scalable platform for future growth.

As of December 31, 2010, we had interest rate swaps with a notional amount of $250.0 million, which do not currently qualify for "hedge accounting" treatment provided by accounting standards for derivatives and hedges. Accordingly, all mark-to-market adjustments on these swaps are recorded through the income statement. As of December 31, 2010, the mark-to-market value of these swaps was a liability of $54.0 million. In 2010, we recorded an unrealized mark-to-market after-tax loss of $9.9 million on these swaps. Fluctuations in interest rates create volatility in the fair value of these swaps which will likely have an impact on our 2011 earnings as we record the associated unrealized mark-to-market gains or losses within our income statement.

Results of Operations

Executive Summary and Overview

		2010		2009		2008
				(in thousands)		
Revenue:						
Utilities	$	1,120,721	$	1,100,204	$	749,250
Non-regulated Energy		186,530		169,374		256,540
	$	1,307,251	$	1,269,578	$	1,005,790

		2010		2009		2008
				(in thousands)		
Income (loss) from continuing operations:						
Utilities	$	74,563	$	57,071	$	43,904
Non-regulated Energy		13,616		579		(23,345)
Corporate		(19,494)		21,106		(72,596)
	$	68,685	$	78,756	$	(52,037)

		2010		2009		2008
				(in thousands)		
Net income:						
Utilities	$	74,563	$	57,071	$	43,904
Non-regulated Energy		13,616		1,938		(5,312)
Corporate		(19,494)		22,546		66,488
	$	68,685	$	81,555	$	105,080

The following business group and segment information does not include discontinued operations or intercompany eliminations. Amounts are presented on a pre-tax basis unless otherwise indicated.

2010 Compared to 2009

Income from continuing operations was $68.7 million, or $1.76 per share, in 2010 compared to $78.8 million, or $2.04 per share, in 2009. The 2010 Income from continuing operations includes gains on sale of $5.8 million after-tax of a 23% ownership interest in the Wygen III plant and assets sold by Nebraska Gas after the annexation of a service area by the City of Omaha, Nebraska; and a $9.9 million after-tax non-cash mark-to-market loss on certain interest rate swaps. The 2009 Income from continuing operations includes a gain on sale of $16.9 million after-tax of a 23.5% ownership interest in the Wygen I plant; a $36.2 million after-tax non-cash mark-to-market gain on certain interest rate swaps; and a $27.8 million after-tax non-cash ceiling test impairment at our Oil and Gas segment.

Net income available to common stock was $68.7 million, or $1.76 per share, in 2010 compared to Net income available to common stock of $81.6 million, or $2.11 per share, in 2009. In addition to the items mentioned above in Income from continuing operations, the 2009 Net income also includes $2.8 million after-tax income from discontinued operations related to the operations sold in the IPP Transaction.

Highlights of our business groups are as follows:

Utilities Group

The Utilities Group's Income from continuing operations was $74.6 million in 2010, compared to Income from continuing operations of $57.1 million in 2009. Our Electric Utilities were positively impacted by approved rate cases and an increase in off-system sales margins. Our Gas Utilities recorded increased margins due to the impact of rate increases that were not in effect for the entire year of 2009. Additional highlights of the Utilities Group include the following:

- New and interim rates were implemented in five utility jurisdictions increasing annual revenues $47.1 million:

Utility	State	Effective Date	Annual Revenue Increase (in millions)	
Black Hills Power	SD	4/1/2010	$	15.2
Black Hills Power	WY	6/1/2010		3.1
Colorado Electric	CO	8/6/2010		17.9
Nebraska Gas	NE	9/1/2010		8.3
Iowa Gas [(a)]	IA	6/18/2010		2.6
			$	47.1

(a) In June 2010, Iowa Gas filed a request for a $4.7 million increase in annual revenues with the IUB. Interim rates reflecting an annual revenue increase of $2.6 million went into effect on June 18, 2010. In August 2010, we reached a settlement with the OCA for a revenue increase of $3.4 million. This settlement agreement was modified and re-filed on January 11, 2011. The modified settlement excludes the integrity investment tracker and the three-year rate moratorium included in the original settlement agreement filed on September 1, 2010, which was not approved by the IUB. Approval of the modified settlement was received from the IUB on February 10, 2011.

- Construction of gas-fired generation to serve Colorado Electric customers is moving forward to start providing energy by January 1, 2012. The 180 MW generation project, including transmission, is expected to cost between $250 million and $260 million, of which $182.8 million has been expended through December 31, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment;
- The Wygen III generating facility commenced commercial operations on April 1, 2010. In July 2010, Black Hills Power sold a 23% ownership interest in the Wygen III power generation facility to the City of Gillette for $62.0 million. A gain of $6.2 million was recognized on the sale;
- On October 1, 2010 Black Hills Power suspended the operations of its 62 year old, 34.5 MW coal-fired Osage Power Plant located in Osage, Wyoming. We now have more economical power supply alternatives available to provide for present customer energy demands; however, the plant's operating permits will be retained so that full operations can be restored if needed;
- Our Electric Utilities reached agreement with the DOE for smart grid funding through matching grants totaling $20.7 million, made available through the American Recovery and Reinvestment Act of 2009. As of December 31, 2010, we have completed 100% of the installations related to these meters;
- Due to the annexation of an outlying suburb by the City of Omaha, Nebraska, Nebraska Gas transferred assets serving approximately 3,000 customers to Metropolitan Utilities District on March 2, 2010. Nebraska Gas received $6.1 million in cash and recognized a $2.7 million gain on the sale of assets in the first quarter of 2010; and
- In December 2010, Colorado Electric received a final order from the CPUC regarding its plan to comply with the Colorado Clean Air, Clean Jobs Act. The order approved the retirement of the utility's 42 MW W.N. Clark coal-fired generation facility, and granted a presumption of need for replacement of the plant. The utility proposes to construct a third 92 MW General Electric LMS100 natural gas-fired turbine at the site of our Pueblo Airport Generation Station currently under construction. Colorado Electric will file a Certificate of Public Convenience and Necessity in the first quarter of 2011 that will provide additional justification for the incremental 50 MW of generation capacity.

Non-regulated Energy Group

Income from continuing operations was $13.6 million in 2010 for the Non-regulated Energy Group compared to Income from continuing operations of $0.6 million in the same period in 2009. Highlights of the Non-regulated Energy Group include the following:

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- Construction of gas-fired generation at Black Hills Colorado IPP to serve a 20-year PPA with Colorado Electric is moving forward to start providing energy by January 1, 2012. The 200 MW project is expected to cost between $250 million and $260 million, of which $162.6 million has been expended through December 31, 2010. Construction commenced in July 2010 subsequent to the City of Pueblo annexing our site into the city and the receipt of the final air permit from the State of Colorado Department of Public Health and Environment;
- In May 2010, Enserco entered into a two-year $250 million committed stand-alone credit facility. The new facility includes a $100 million accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to $350 million;
- In June 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business for $2.25 million. Late in the third quarter of 2010, Enserco further expanded business lines to include power and environmental marketing. Our risk tolerances and capital allocated to the energy marketing segment are expected to remain the same;
- The first quarter of 2009 included a $16.9 million after-tax gain at our Power Generation segment on the sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility; and
- The first quarter of 2009 included a $27.8 million after-tax non-cash ceiling test impairment charge due to a write-down in value of our natural gas and crude oil properties resulting from low quarter-end prices for the commodities at our Oil and Gas segment.

Corporate

Loss from continuing operations was $19.5 million in 2010 compared to Income from continuing operations of $21.1 million in the same period in 2009. The Corporate activities include the following:

- We recognized a non-cash unrealized mark-to-market loss related to certain interest rate swaps of $15.2 million in 2010 compared to a $55.7 million unrealized gain on these swaps for the same period in 2009;
- In April 2010, we entered into a new three-year $500 million Revolving Credit Facility, which includes a $100 million accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the new facility to $600 million. The Revolving Credit Facility will be used to fund working capital needs and for other corporate purposes;
- In July 2010, we completed a public offering of $200 million aggregate principal amount of senior unsecured notes due July 15, 2020. The notes were priced at par and carry an interest rate of 5.875%;
- In November 2010, we entered into an equity forward offering for 4,000,000 shares. The offering will provide net proceeds of approximately $113.4 million. In December 2010, the underwriters exercised their option and purchased 413,519 additional shares netting an additional $11.7 million, bringing the total net proceeds to $125.1 million. We may settle the equity forward instruments at any time up to the maturity date of November 11, 2011;
- In December 2010, we entered into a $100 million unsecured one-year term loan. The cost of borrowings under the loan is based on a spread of 137.5 basis points over LIBOR; and
- We recorded a $2.4 million reduction in tax expense reflecting a re-measurement of a tax position in accordance with accounting for uncertain tax positions. Approximately $2.0 million of this benefit was recorded in the Corporate segment. The re-measurement was prompted by a settlement agreement that was reached with the IRS Appeals Division primarily in regards to tax depreciation method changes.

2009 Compared to 2008

Income from continuing operations was $78.8 million, or $2.04 per share, in 2009 compared to a Loss from continuing operations of $52.0 million, or $1.37 per share for 2008. The 2009 Income from continuing operations includes a gain on sale of $16.9 million after-tax of a 23.5% ownership interest in the Wygen I plant; a $36.2 million unrealized after-tax non-cash mark-to-market gain on certain interest rate swaps; and a $27.8 million after-tax impact of a non-cash ceiling test impairment at our Oil and Gas segment. Results also reflect a full year of operations for the utilities purchased in the Aquila Transaction. The 2008 Loss from continuing operations includes a $61.4 million unrealized after-tax non-cash mark-to-market loss on certain interest rate swaps; and a $59.0 million after-tax loss of a non-cash ceiling test impairment at our Oil and Gas segment.

Net income available for common stock was $81.6 million, or $2.11 per share, in 2009 compared to $105.1 million or $2.75 per share for 2008. In addition to the items mentioned in Income from continuing operations, the 2008 Net income includes $157.2 million after-tax income from discontinued operations including a substantial gain on the completion of the IPP Transaction.

Highlights of our business groups are as follows:

Utilities Group

The Utilities Group's Income from continuing operations for 2009 was $57.1 million in 2009, compared to $43.9 million in 2008. Income from continuing operations at the Electric Utilities was impacted $7.6 million by low off-system sales margins due to low commodity prices while income from continuing operations at the Gas Utilities was strong due to favorable weather. In addition, 2009 Utilities Group highlights include the following:

- New and interim rates were implemented in four utility jurisdictions increasing annual revenues by $16.5 million:

Utility	State	Effective Date	Annual Revenue Increase (in millions)
Black Hills Power	SD/WY	1/1/2009	$ 3.8
Iowa Gas	IA	7/31/2009	10.8
Colorado Gas	CO	4/1/2009	1.4
Kansas Gas	NE	10/1/2009	0.5
			$ 16.5

- Construction of the Wygen III generation facility project continued in 2009. A 25% ownership interest in this generation facility was sold in April 2009. AFUDC increased $4.0 million related to this construction;
- Colorado Electric continued plans and purchases to construct 180 MW of utility-owned, gas-fired generation. AFUDC increased $1.2 million due to this construction activity;
- Black Hills Power completed a first mortgage bond for $180.0 million. The bonds carry an interest rate of 6.125% and mature in November 2039. Interest from this debt and other debt transactions increased interest expense by $12.7 million;
- We completed the repayment of $383.0 million of borrowings on our Acquisition Facility which was used to finance the Aquila Transaction on July 14, 2008; and
- We completed our first full year of operations for Colorado Electric and the Gas Utilities acquired in the Aquila Transaction.

Non-Regulated Energy Group

Income from continuing operations was $0.6 million in 2009 for the Non-regulated Group compared to a Loss from continuing operations of $23.3 million in 2008. Our Energy Marketing and Oil and Gas segments were impacted significantly by low commodity prices. In addition, 2009 Non-regulated Energy Group highlights include the following:

- Oil and Gas recorded a $27.8 million non-cash after-tax ceiling test impairment loss in 2009 compared to a $59.0 million non-cash after-tax ceiling test impairment loss in 2008;
- Power Generation's improved earnings reflect a gain of $26.0 million for the sale of a 23.5% ownership interest in the Wygen I power generation facility to MEAN;
- Our Coal Mining segment executed a site lease agreement with the owners of the Wygen III plant increasing earnings $2.9 million for rental revenue in 2009;
- Energy Marketing completed a one-year $300 million committed stand-alone credit facility in May 2009, to replace its previously uncommitted $300.0 million credit facility;
- Black Hills Wyoming completed $120.0 million in project financing in December 2009. The loan matures in December 2016 with an interest rate of LIBOR plus 3.25% per annum; and
- Black Hills Colorado IPP was selected to provide power to Colorado Electric and began planning and purchasing to build 200 MW of natural gas-fired electric generation to sell to Colorado Electric through a 20-year PPA.

Corporate

- We recorded an unrealized mark-to-market gain related to certain interest rate swaps of $55.7 million in 2009 compared to a $94.4 million loss recognized in 2008; and
- We completed a $250.0 million public offering of senior notes due in 2014 in May 2009. The notes were priced at par and carry an interest rate of 9%.

A discussion of operating results from our business segments follows.

Utilities Group

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2010	2009	2008[(a)]
Revenue - electric	$ 532,423	$ 485,152	$ 425,123
Revenue - Cheyenne Light gas	37,591	35,613	48,296
Total revenue	570,014	520,765	473,419
Fuel and purchased power - electric	269,747	260,150	222,826
Purchased gas - Cheyenne Light	23,064	20,859	33,735
Total fuel and purchased power	292,811	281,009	256,561
Gross margin - electric	262,676	225,002	202,297
Gross margin - Cheyenne Light gas	14,527	14,754	14,561
Total gross margin	277,203	239,756	216,858
Operations and maintenance	136,873	125,150	101,344
Gain on sale of operating asset	(6,238)	—	—
Depreciation and amortization	47,276	43,638	37,648
Total operating expenses	177,911	168,788	138,992
Operating income	99,292	70,968	77,866
Interest expense, net	37,043	33,012	23,294
Other income	(3,215)	(7,869)	(3,984)
Income tax expense	18,012	13,126	18,882
Income from continuing operations and net income	$ 47,452	$ 32,699	$ 39,674

(a) 2008 results include the operations of Colorado Electric acquired on July 14, 2008.

	2010	2009	2008
Regulated power plant fleet availability:			
Coal-fired plants	93.9 %	92.1 %	93.7 %
Other plants	96.2 %	96.9 %	91.4 %
Total availability	94.8 %	94.0 %	92.8 %

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2010 Compared to 2009

Income from continuing operations was $47.5 million in 2010 compared to $32.7 million in 2009 as a result of:

Gross margin: Gross margin increased $37.4 million primarily due to a $25.5 million increase related to the impact of the outcome of the Black Hills Power and Colorado Electric rate cases, an increase of $3.4 million for updated transmission cost adjustments at Colorado Electric, an increase of $4.6 million in off-system sales margin as a result of a change in the methodology used at Black Hills Power to allocate the cost of renewable resources and firm purchases, and increased intercompany revenues of $4.3 million due to a new shared services agreement related to resources utilized by affiliated entities.

Operations and maintenance: Operations and maintenance expenses increased $11.7 million primarily due to additional costs of $6.8 million associated with the operations of Wygen III, which commenced commercial operation on April 1, 2010, increased intercompany costs of $1.6 million related to a new shared services agreement, and costs of $2.0 million associated with a major overhaul at the Ben French plant.

Gain on sale of operating assets: A $6.2 million gain on sale was recognized on the sale of a 23% ownership interest in the Wygen III generating facility to the City of Gillette.

Depreciation and amortization: Depreciation and amortization increased $3.6 million primarily due to the addition of the Wygen III plant placed into service on April 1, 2010.

Interest expense, net: Interest expense, net increased $4.0 million due to higher net interest expense of $8.6 million compared to the same period in the prior year due to debt incurred for plant construction and as a result of higher rates associated with long-term financings in 2010 compared to rates on short-term debt held in 2009, partially offset by an increase in AFUDC-borrowed of $4.6 million. AFUDC-borrowed increased $6.7 million at Colorado Electric for the plant construction, offset by a decrease in AFUDC-borrowed at Black Hills Power of $2.1 million due to the commencement of commercial operations of Wygen III.

Other income: Other income decreased $4.7 million primarily due to lower AFUDC-equity of $3.1 million, which decreased upon the placement of Wygen III into commercial operations on April 1, 2010. Additionally, 2009 included a gain of $1.1 million from the sale of SO_2 emission credits.

Income tax expense: The effective tax rate decreased primarily as a result of a $2.2 million tax benefit for a rate case settlement related to expensing certain items that had been capitalized for income tax purposes, partially offset by lower benefit from AFUDC-equity which decreased upon commercial operations of Wygen III.

2009 Compared to 2008

2009 results include a full year of operations at Colorado Electric, which was acquired on July 14, 2008.

Income from continuing operations was $32.7 million in 2009 compared to $39.7 million in 2008 as a result of:

Gross margin: Gross margins reflect the acquisition of Colorado Electric in July 2008 in addition to a $7.6 million decrease in margins from off-system sales reflecting the lower margins available in the current low energy price environment partially offset by a $6.5 million increase in other margins primarily due to an increase in transmission rates effective January 1, 2009 at Black Hills Power.

Operations and maintenance: Operations and maintenance expenses increased primarily due to the acquisition of Colorado Electric in July 2008.

Depreciation and amortization: Depreciation and amortization costs increased $6.0 million primarily due to additional depreciation associated with the acquisition of Colorado Electric in July 2008.

Interest expense, net: Interest expense, net increased $9.7 million primarily due to additional debt associated with the acquisition of Colorado Electric, additional long-term project debt at Black Hills Power, and inter-segment debt restructuring at Colorado Electric, partially offset by AFUDC-borrowed.

Other income: Other income increased $3.9 million primarily due to an increase in AFUDC-equity of $2.1 million from the construction of Wygen III in 2009 and the sale of SO_2 emission credits of $1.1 million by Black Hills Power.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2010	2009	For the Period July 14, 2008 to December 31, 2008
Revenue:			
Natural gas - regulated	$ 520,691	$ 553,576	$ 261,887
Other - non-regulated	30,016	26,736	15,189
Total sales	550,707	580,312	277,076
Cost of sales:			
Natural gas - regulated	316,546	356,623	180,556
Other - non-regulated	17,171	15,093	11,294
Total cost of sales	333,717	371,716	191,850
Gross margin:			
Natural gas - regulated	204,145	196,953	81,331
Other non-regulated	12,845	11,643	3,895
Total gross margin	216,990	208,596	85,226
Operations and maintenance	125,447	123,296	56,196
Gain on sale of operating assets	(2,683)	—	—
Depreciation and amortization	25,258	30,090	14,142
Total operating expenses	148,022	153,386	70,338
Operating income	68,968	55,210	14,888
Interest expense, net	27,455	17,100	8,125
Other expense (income)	(47)	285	86
Income tax expense	14,449	13,453	2,447
Income from continuing operations and net income	$ 27,111	$ 24,372	$ 4,230

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2010 Compared to 2009

Income from continuing operations was $27.1 million in 2010 compared to $24.4 million in 2009 as a result of:

Gross margin: Gross margin increased $8.4 million primarily due to new and interim rates at Iowa Gas, Nebraska Gas and Colorado Gas, and an approved Gas System Reliability surcharge at Kansas Gas, which were not effective for a full year in 2009, partially offset by lower volumes as a result of milder weather.

Operations and maintenance: Operations and maintenance expenses increased $2.2 million primarily due to increases in employee benefit costs, workers compensation insurance and litigation related accruals.

Gain on sale of operating assets: A $2.7 million gain on sale was recognized on assets transferred by Nebraska Gas to the City of Omaha, Nebraska after a portion of Nebraska Gas' service territory was annexed by the City.

Depreciation and amortization: Depreciation and amortization decreased $4.8 million primarily due to assets becoming fully depreciated during 2009 and 2010.

Interest expense, net: Interest expense, net increased $10.4 million primarily due to higher interest rates within the assigned capital structure.

Other expense: Other expense was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for 2010 was comparable to the effective tax rate in the prior year.

2009 Compared to 2008

The Gas Utilities located in Colorado, Nebraska, Iowa and Kansas were acquired on July 14, 2008. Income from continuing operations was $24.4 million in 2009, compared to $4.2 million in 2008. The increase was primarily due to a full year of Gas Utilities operation in 2009 compared to the partial year in 2008. Natural gas demand is typically higher in the first and fourth quarters as gas is 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 addition to a full year of operations at the Gas Utilities, results were impacted by favorable weather as well as rate increases from general rate cases in Colorado ($1.4 million annual increase effective April 1, 2009), general rate cases in Iowa ($10.8 million annual increase effective July 27, 2009), and from cost tracking riders in Kansas ($0.5 million annual increase effective September 14, 2009).

Non-regulated Energy Group

Oil and Gas

Oil and Gas operating results for the years ended December 31 were as follows (in thousands):

	2010	2009	2008
Revenue	$ 74,164	$ 70,684	$ 106,347
Operations and maintenance	39,299	40,224	47,204
Depreciation, depletion and amortization	30,283	29,680	38,549
Impairment of long-lived assets	—	43,301	91,782
Total operating expenses	69,582	113,205	177,535
Operating income (loss)	4,582	(42,521)	(71,188)
Interest expense, net	5,372	4,673	5,092
Other income	(722)	(350)	(611)
Income tax (benefit) expense	(425)	(21,016)	(26,001)
Income (loss) from continuing operations and net income (loss)	$ 357	$ (25,828)	$ (49,668)

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

Crude Oil and Natural Gas Production	2010	2009	2008
Bbls of oil sold	375,650	366,000	387,400
Mcf of natural gas sold	9,046,500	10,266,900	11,209,600
Mcf equivalent sales	11,300,400	12,462,900	13,534,000

Average Price Received [(a)]	2010	2009	2008
Gas/Mcf[(b)]	$ 4.85	$ 4.71	$ 6.44
Oil/Bbl	$ 75.59	$ 59.19	$ 79.35

(a) Net of hedge settlement gains/losses
(b) Exclusive of gas liquids

	2010	2009	2008
Depletion expense/Mcfe*	$ 2.36	$ 2.16	$ 2.68

* 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 2009 rate was particularly impacted by a lower asset base as a result of previous asset impairment charges. This impact was partially offset by persistent low product prices during the year, which resulted in lower oil and gas reserve quantities.

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

	2010			
	LOE	Gathering Compression and Processing [(a)]	Production Taxes	Total
San Juan	$ 1.30	$ 0.34	$ 0.54	$ 2.18
Piceance	0.68	0.64	(0.09)	1.23
Powder River	1.20	—	1.02	2.22
Williston	0.92	—	1.03	1.95
All other properties	0.92	—	0.25	1.17
Total	$ 1.13	$ 0.22	$ 0.55	$ 1.90

	2009			
	LOE	Gathering Compression and Processing [(a)]	Production Taxes	Total
San Juan	$ 1.27	$ 0.28	$ 0.47	$ 2.02
Piceance	1.06	0.41	0.25	1.72
Powder River	1.36	—	0.72	2.08
Williston	0.67	—	0.88	1.55
All other properties	1.08	0.04	0.25	1.37
Total	$ 1.22	$ 0.18	$ 0.46	$ 1.86

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	2008			
	LOE	Gathering Compression and Processing [(a)]	Production Taxes	Total
San Juan	$ 1.47	$ 0.24	$ 0.94	$ 2.65
Piceance	1.29	0.77	0.45	2.51
Powder River	1.52	—	1.44	2.96
Williston	1.09	—	0.99	2.08
All other properties	0.88	0.11	0.49	1.48
Total	$ 1.33	$ 0.20	$ 0.91	$ 2.44

(a) During the first quarter of 2010, our Oil and Gas segment transferred midstream assets to a new subsidiary in our Energy Marketing segment. As a result, 2009 and 2008 Gathering, Compression and Processing have been modified to reflect the removal of these assets for comparative purposes.

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:

	2010	2009	2008
Bbls of oil (in thousands)	5,940	5,274	5,185
MMcf of natural gas	95,456	87,660	154,432
Total MMcfe	131,096	119,304	185,542

Reserves are based on reports prepared by an independent consulting and engineering firm. The reports were prepared by CG&A. Reserves were determined using SEC-defined product prices. 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. The current estimate takes into account 2010 production of approximately 10.7 Bcfe, additions from extensions, discoveries and acquisitions of 8.6 Bcfe and positive revisions to previous estimates of 14.4 Bcfe, primarily due to higher product prices.

Reserves reflect SEC-defined pricing held constant for the life of the reserves, as follows:

	2010		2009		2008	
	Oil	Gas	Oil	Gas	Oil [(1)]	Gas [(1)]
NYMEX prices	$ 79.43	$ 4.38	$ 61.18	$ 3.87	$ 44.60	$ 5.71
Well-head reserve prices	$ 70.82	$ 3.45	$ 53.59	$ 2.52	$ 32.74	$ 4.44

(1) On December 31, 2008, the SEC issued final rules amending its oil and gas reserve reporting requirements effective for years ending on or after December 31, 2009. The final rule changed the use of prices at the end of each reporting period to an average of the first day of the month for the preceding twelve months held constant for the life of production. Previously, the rule required the use of the spot price on the last day of the reporting period, held constant for the life of production.

2010 Compared to 2009

Income from continuing operations was $0.4 million in 2010 compared to a Loss from continuing operations of $25.8 million in 2009 as a result of:

Revenue: Revenue increased $3.5 million primarily due to a 28% and 3% increase in the annual average hedged price of oil and gas, respectively, and a 3% increase in oil production, partially offset by a decrease of 12% in gas production. The increase in oil production is primarily due to production of new wells in our ongoing Bakken drilling program. The decrease in natural gas

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production was largely driven by natural production declines from producing properties, and reduced capital deployment during 2010 and 2009.

Operations and maintenance: Operations and maintenance expenses decreased $0.9 million primarily as a result of cost containment efforts.

Impairment of long-lived assets: 2009 results reflect a $43.3 million non-cash ceiling test impairment charge taken during the first quarter of 2009. The write-down in the net carrying value of our natural gas and crude oil properties resulted from low March 31, 2009 quarter-end natural gas prices for the commodities. The write-down of gas and oil properties was based on period end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense increased $0.6 million primarily due to an increased depletion rate per Mcfe resulting from increasing investment in our ongoing Bakken formation drilling program, partially offset by a decrease in volumes sold.

Interest expense, net: Interest expense, net increased $0.7 million primarily due to increased interest rates.

Other Income: Other income was comparable to the same period in the prior year.

Income tax expense: The effective tax rate in 2010 includes a tax benefit related to percentage depletion and a $0.4 million re-measurement of a previously recorded uncertain tax position prompted by a settlement with the IRS Appeals Division. The tax position related to tax depreciation method changes. The effective tax rate in 2009 was impacted by a tax benefit of $3.8 million related to a positive adjustment of a previously recorded tax position.

2009 Compared to 2008

Loss from continuing operations was $25.8 million compared to a Loss from continuing operations of $49.7 million in 2008 as a result of:

Revenue: Revenue decreased $35.7 million primarily due to a 25% and 27% decrease in the annual average hedged price of oil and gas received, respectively, and a 6% and 8% decrease in oil and gas production, respectively. The decrease in natural gas production is due to a lower level of capital spending than in prior years and a voluntary shut-in of production at properties with the highest operating costs. Shut-ins reduced production for the year ended December 31, 2009 by approximately 458 MMcfe.

Operations and maintenance: Operations and maintenance expenses decreased $7.0 million primarily due to decreased LOE of $2.8 million as a result of lower production and cost reduction efforts and decreased production taxes of approximately $6.6 million primarily due to lower oil and natural gas prices. General and administrative costs increased $3.2 million primarily due to increased costs associated with full employment levels and the associated compensation expense.

Impairment of long-lived assets: A 43.3 million non-cash ceiling test impairment charge was taken during the first quarter of 2009. The write-down in the net carrying value of our natural gas and crude oil properties resulted from low March 31, 2009 quarter-end natural gas prices for the commodities. The write-down of gas and oil properties was based on period end NYMEX prices of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas and $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil. This compares to a $91.8 million non-cash ceiling test impairment charge taken during the fourth quarter 2008. The write-down in value of our natural gas and crude oil properties in 2008 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.

Depreciation, depletion and amortization: Depreciation, depletion and amortization expense decreased $8.9 million primarily due to reduced depletion rate caused by a lower asset base as a result of previous asset impairment charges and lower production.

Interest expense, net; Interest expense, net is comparable to the same period in prior year.

Other Income: Other income was comparable to the same period in the prior year.

Income tax expense: The effective tax rate for 2009 was impacted by a $3.8 million income tax benefit related to an adjustment of a previously recorded tax position.

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2010	2009	2008
Revenue	$ 30,349	$ 30,575	$ 38,181
Operations and maintenance	16,210	12,631	19,339
Depreciation and amortization	4,466	3,860	4,627
Gain on sale of operating asset	—	25,971	—
Total operating expenses	20,676	(9,480)	23,966
Operating income	9,673	40,055	14,215
Interest expense, net	8,110	9,388	11,649
Other (income) expense	(854)	(1,091)	(3,698)
Income tax expense	266	11,097	3,013
Income from continuing operations and net income	$ 2,151	$ 20,661	$ 3,251

The following table provides certain operating statistics for the Power Generation segment at December 31:

	2010	2009	2008
Independent power capacity:			
MW of independent power capacity in service	120	120	141
Contracted fleet plant availability:			
Gas-fired plants	99.9 %	92.0 %	96.2 %
Coal-fired plants	98.5 %	96.1 %	95.3 %
Total	99.1 %	94.4 %	95.9 %

2010 Compared to 2009

Income from continuing operations was $2.2 million in 2010 compared to $20.7 million in 2009 as a result of:

Revenue: Revenue in 2010 was comparable to the same period in the prior year.

Operations and maintenance: Operations and maintenance expense increased $3.6 million primarily due to maintenance costs for a major overhaul and extended outage at Wygen I and increased transmission costs.

Gain on sale of operating assets: The gain on sale of operating assets in 2009 of $26.0 million represented the sale of a 23.5% ownership interest in the Wygen I power generation facility.

Depreciation and amortization: Depreciation and amortization were comparable to the same period in the prior year.

Interest expense, net: Interest expense, net decreased $1.3 million primarily due to a decrease in debt from an intercompany debt restructuring partially offset by interest expense associated with the $120 million project financing at Black Hills Wyoming.

Other income: Other income in 2010 was comparable to other income in 2009.

Income tax expense: The effective tax rate for 2010 decreased compared to 2009 primarily due to the effect of research and development tax credits.

2009 Compared to 2008

Income from continuing operations was $20.7 million in 2009 compared to $3.3 million in 2008 as a result of:

Revenue: Revenues decreased $7.6 million primarily from replacing a 20-year PPA with an operating and site lease agreement related to MEAN's purchase of a 23.5% ownership interest in Wygen I.

Operations and maintenance: Operations and maintenance decreased $6.7 million primarily due to 2008 operating expenses including $3.1 million of allocated indirect costs relating to the IPP assets sold and not reclassified to discontinued operations in accordance with accounting guidance for discontinued operations and a decrease of $1.9 million reflecting net earnings impact of replacing a 20 MW PPA with operating and site lease agreements related to MEAN's purchase of a 23.5% ownership interest in Wygen I.

Gain on sale of operating assets: The gain on sale of operating assets of $26.0 million represents the sale of a 23.5% ownership interest in the Wygen I power generation facility.

Depreciation and amortization: Depreciation and amortization decreased $0.8 million primarily due to the impact of selling 23.5% ownership in the Wygen I plant.

Interest expense, net: Interest expense, net decreased $2.3 million primarily due to interest expense in 2008 including $8.7 million of allocated net interest expense relating to the IPP assets sold and not reclassified to discontinued operations in accordance with accounting guidance for discontinued operations partially offset in 2009 by an increase in interest expense of $6.4 million primarily due to a change in intersegment debt to equity capital structure.

Other (income) expenses: Other income decreased $2.6 million primarily due to the inclusion of a $2.7 million gain on the sale of excess emission credits in 2008, which were made available by the decommissioning of the Ontario facility.

Income tax expense: The 2008 effective tax rate was impacted by the sale of seven IPP facilities in July 2008.

Coal Mining

Coal Mining operating results for the years ended December 31 were as follows (in thousands):

	2010	2009	2008
Revenue	$ 57,842	$ 58,490	$ 56,901
Operations and maintenance	34,028	40,312	43,159
Depreciation, depletion and amortization	19,083	13,123	9,449
Total operating expenses	53,111	53,435	52,608
Operating income	4,731	5,055	4,293
Interest income, net	(3,180)	(1,452)	(1,346)
Other income	(2,149)	(3,475)	(584)
Income tax expense	2,379	3,234	2,190
Income from continuing operations	$ 7,681	$ 6,748	$ 4,033

The following table provides certain operating statistics for the Coal Mining segment (in thousands):

	2010	2009	2008
Tons of coal sold	5,931	5,955	6,017
Cubic yards of overburden moved	15,679	14,539	12,203
Coal reserves	261,860	268,000	274,000

2010 Compared to 2009

Income from continuing operations was $7.7 million in 2010 compared to $6.7 million in 2009 as a result of:

Revenue: Revenue decreased $0.6 million primarily due to a lower price on coal contracts. There was a slight decrease in volumes sold primarily due to customer plant outages and lower demand for coal, offset by sales to Wygen III, which commenced commercial operations in April 2010.

Operations and maintenance: Operations and maintenance expenses decreased $6.3 million. During 2010, the company received approval from the State of Wyoming's Department of Environmental Quality for a revised post-mining topography plan. The new plan includes a more efficient method of conducting final reclamation of the mine site by re-assessing the handling of overburden. Accordingly, a higher percentage of our overburden removal activities also qualify as reclamation backfill activities. This change resulted in lower operations expense and a related increase in depletion of reclamation costs. Cubic yards of overburden moved increased 8%.

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $6.0 million primarily due to an increase in depletion of reclamation costs as discussed in Operations and Maintenance.

Interest income, net: Interest income, net increased $1.7 million primarily due to increased lending to affiliates at higher interest rates.

Other income: Other income decreased $1.3 million primarily due to lower rental income related to the Wygen III site lease. The site lease was entered into in the third quarter of 2009 with billings back to March 2008.

Income tax expense: The effective tax rate decreased primarily due to an increased tax benefit generated by percentage depletion.

2009 Compared to 2008

Income from continuing operations was $6.7 million in 2009 compared to $4.0 million in 2008 as a result of:

Revenue: Revenue increased $1.6 million primarily due to a higher average price received, partially offset by lower coal volumes sold. The higher average price received includes the impact of sales prices to our regulated utility subsidiaries that are determined in part by a return on investment base.

Operations and maintenance: Operations and maintenance expenses decreased $2.8 million primarily due to lower estimated future reclamation costs.

Depreciation, depletion and amortization: Depreciation, depletion and amortization increased $3.7 million primarily due to an increased asset base and usage.

Interest income, net: Interest income, net was comparable to the same period in the prior year.

Other income: Other income increased $2.9 million primarily due to rental income related to the Wygen III site lease. The site lease was entered into in the third quarter of 2009 with billings back to March 2008.

Income taxes: The effective tax rate was lower primarily due to the tax benefit generated by percentage depletion.

Energy Marketing

Our Energy Marketing operating results for the years ended December 31 were as follows (in thousands):

	2010	2009	2008
Revenue and gross margin:			
Realized gas marketing gross margin	$ 24,536	$ 30,134	$ 18,593
Unrealized gas marketing gross margin	(6,777)	(19,777)	33,247
Realized oil marketing gross margin	8,888	11,278	1,038
Unrealized oil marketing gross margin	1,663	(8,254)	6,432
Realized coal marketing gross margin [(a)]	1,541	—	—
Unrealized coal marketing gross margin [(a)]	2,012	—	—
Realized power marketing margin [(b)]	(2,467)	—	—
Unrealized power marketing margin [(b)]	(1,397)	—	—
Realized environmental marketing margin [(b)]	—	—	—
Unrealized environmental marketing margin [(b)]	—	—	—
Total revenue and gross margins	27,999	13,381	59,310
Operations	20,213	13,279	28,486
Depreciation and amortization	527	525	689
Total operating costs	20,740	13,804	29,175
Operating income (loss)	7,259	(423)	30,135
Interest expense, net	2,199	1,547	254
Other (income) expense	(152)	(22)	12
Income tax expense (benefit)	1,895	(460)	10,180
Income (loss) from continuing operations and net income (loss)	$ 3,317	$ (1,488)	$ 19,689

(a) Coal margins include activity beginning June 1, 2010, the acquisition date of the coal marketing portfolio.
(b) Power and environmental marketing margins include activity from the commencement of operations late in the third quarter of 2010.

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

	2010	2009	2008
Natural gas average daily physical sales - MMBtu	1,586,000	1,974,300	1,873,400
Crude oil average daily physical sales - Bbls	18,455	12,400	7,880
Coal average daily physical sales - Tons	33,250	—	—

2010 Compared to 2009

Income from continuing operations was $3.3 million in 2010 compared to a Loss from continuing operations of $1.5 million in 2009 as a result of:

Revenue and gross margin: Revenue and gross margin increased $14.6 million primarily due to higher incremental margins in the areas of natural gas and oil marketing. Coal marketing, which was acquired in June 2010, produced positive incremental margins, partially offset by losses in power marketing.

Operations: Operations expense increased $6.9 million primarily due to higher provisions for incentive compensation expense related to increased gross margins, increased bank fees as a result of higher letters of credit due to a higher utilization level, and increased costs associated with employee additions required for marketing commodities added in 2010.

Depreciation and amortization: Depreciation and amortization were comparable to the same period in prior year.

Interest expense, net: Interest expense, net increased $0.7 million primarily due to decreased interest income partially offset by decreased amortization expense related to the credit facility costs.

Other (income) expense: Other (income) expense was comparable to the same period in the prior year.

Income tax (benefit) expense: Tax expense was recorded for the year ended December 31, 2010, compared to a tax benefit for the same period in the prior year.

2009 Compared to 2008

Loss from continuing operations was $1.5 million in 2009 compared to Income from continuing operations of $19.7 million in 2008 as a result of:

Revenue and gross margin: Revenue and gross margin decreased $45.9 million due to a $67.7 million decrease in unrealized marketing margins, primarily due to prevailing conditions in natural gas markets affecting both transportation and storage strategies. Unrealized mark-to-market gains in 2008 were driven by accelerated margins within our proprietary trading portfolio and narrowing basis differentials at year end that resulted in unrealized mark-to-market gains on our hedged transportation positions. Those positions were settled and the margins realized primarily in 2009 and to a lesser extent in 2010. The decrease in margins was partially offset by a $21.8 million increase in realized marketing margins primarily due to settlement of trades which produced unrealized gains in the previous year.

Operations: Operations costs decreased $15.2 million primarily due to a lower provision for incentive compensation.

Depreciation and amortization: Depreciation and amortization were comparable to the same period in prior year.

Interest expense, net: Interest expense, net increased $1.3 million primarily due to increased credit facility costs for the new committed credit facility.

Other (income) expense: Other (income) expense was comparable to the same period in prior year.

Income tax (benefit) expense: The tax benefit for the year ended 2009 increased due to a 2008 tax true-up adjustment recorded in 2009.

Corporate

2010 Compared to 2009

Loss from continuing operations was $19.5 million in 2010 compared to Income from continuing operations of $21.1 million in 2009 as a result of:

- A $15.2 million unrealized mark-to-market loss in 2010 related to certain interest rate swaps that are no longer designated as hedges for accounting purposes compared to a $55.7 million unrealized mark-to-market gain in 2009; and
- A $1.4 million increase in net interest expense primarily due to interest settlements of the de-designated interest rate swaps.

2009 Compared to 2008

Income from continuing operations was $21.1 million in 2009 compared to a Loss from continuing operations of $72.6 million in 2008 as a result of:

- A $55.7 million unrealized mark-to-market gain in 2009 related to certain interest rate swaps that are no longer designated as hedges for accounting purposes compared to an unrealized mark-to-market loss of $94.4 million in 2008; and
- 2008 included $10.6 million in integration and acquisition costs related to the Aquila Transaction.

Partially offsetting these was:

- A $14.2 million increase in net interest expense primarily due to interest settlements of the de-designated interest rate swaps and amortization of amendment fees to extend the mandatory early termination dates of these swaps through the end of 2010.

Critical Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. 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. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

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

Impairment of Long-lived Assets

We evaluate for impairment, the carrying values of our long-lived assets, including goodwill and other intangibles, whenever indicators of impairment exist and at least annually for goodwill as required by accounting standards.

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 its nature a highly subjective judgment. Significant 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 accounting standards, 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 result in 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, discount rates, inflation rates, and economic conditions, require significant judgment.

We have $354.8 million in goodwill as of December 31, 2010, of which $339.7 million relates to our Black Hills Energy utilities. Colorado Electric carries 69% of the Black Hills Energy goodwill. For the Colorado Electric impairment analysis, we estimate the fair value of the goodwill using a discounted cash flows methodology. This analysis requires the input of several critical assumptions in building our risk-adjusted discount rate and cash flow projections including future growth rates, operating cost escalation rates, amount and timing of growth capital expenditures, timing and level of success in regulatory rate proceedings, and the cost of debt and equity capital. We believe the goodwill amount reflects the value of the opportunity to build a significant amount of rate-base generation and transmission in the next several years followed by the relatively stable,

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long-lived cash flows of the regulated utility business, considering the regulatory environment and market growth potential. The results of the analysis show Colorado Electric with a carrying value of $566.0 million as of November 30, 2010, compared to a fair value of $982.9 million. The fair value exceeds the carrying value by 73.7%; therefore we do not have an impairment.

The Gas Utilities carry the remaining 31% of the Black Hills Energy goodwill. We tested this goodwill for impairment using an EBITDA multiple method and a discounted cash flows method at each reporting unit. The analysis required the input of several critical assumptions in determining EBITDA, the multiple to apply to EBITDA, cash flow projections and risk-adjusted discount rate. These assumptions include future growth rates, operating cost escalation rates, timing and level of success in regulatory rate proceedings, and long-term earnings and merger multiples for comparable companies. The results of the analysis show the Gas Utilities with a carrying value of $527.4 million as of November 30, 2010, compared to a fair value of $899.3 million. The fair value exceeds the carrying value by 70.5%; therefore we do not have an impairment.

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 SEC-defined prices for oil and gas as of 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. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling at March 31, 2009 and December 31, 2008 which required a write-down of $27.8 million after-tax and $59.0 million after-tax, respectively. Under the SEC-defined product prices at December 31, 2010, no additional write-down was required. Reserves in 2010 and 2009 were determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. 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.

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 3, "Risk Management Activities" and Note 4, "Fair Value Measurement," of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Derivatives

Accounting standards for derivatives require 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 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 segment (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. At our Energy Marketing segment, 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. A 20% change to the estimated fair value prices would have affected 2010 net income by approximately $3.2 million.

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. A one basis point move in the interest rate curves over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps have remaining terms of eight and 18 years and have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011.

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. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and by imposing collateral requirements under certain circumstances, including the use of master netting agreements in our energy 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 actual credit losses will be consistent with our estimates.

Pension and Other Postretirement Benefits

The Company, as described in Note 18 to the Consolidated Financial Statements in this Annual Report on Form 10-K, has three defined benefit pension plans and three defined 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. 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 2011 for our non-contributory funded pension plan is expected to be $8.0 million compared to $10.0 million in 2010. The estimated discount rate used to determine annual benefit cost accruals will be 5.5% in 2011; the discount rate used in 2010 was 6.0%. 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 consist of equity, fixed income and real estate securities. In 2010, our target long-term investment allocations were 65% equity and 35% fixed income. At December 31, 2010, our investment allocation was 65% equities, 32% fixed income/cash and 3% real estate.

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 healthcare trend rate for our Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2010 Accumulated Postretirement Benefit Obligation	Impact on 2010 Service and Interest Cost
Increase 1%	$ 2,437	$ 301
Decrease 1%	$ (2,031)	$ (239)

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 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 (dollars, in thousands):

Financial Position Summary	2010	2009	Percentage Change
Cash and cash equivalents	$ 32,438	$ 112,901	(71.3)%
Restricted cash	$ 4,260	$ 17,502	(75.7)%
Short-term debt, including current maturities of long-term debt	$ 254,181	$ 199,745	27.3 %
Long-term debt	$ 1,186,050	$ 1,015,912	16.7 %
Stockholders' equity	$ 1,100,270	$ 1,084,837	1.4 %
Ratios			
Long-term debt ratio	51.9 %	48.4 %	7.2 %
Total debt ratio	56.7 %	52.8 %	7.4 %

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity 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 twelve months.

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 flow needs, which are affected by the seasonality of our businesses. Our principal sources for our long-term capital needs 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.

At December 31, 2010, we had approximately $32.4 million of unrestricted cash on hand in addition to availability under our credit facilities. We had the following borrowings, outstanding letters of credit and available capacity (in millions):

Credit Facility	Expiration	Maximum Capacity	Borrowings at December 31, 2010	Letters of Credit at December 31, 2010	Available Capacity at December 31, 2010
Revolving Credit Facility	April 14, 2013	$ 500.0	$ 149.0	$ 46.9	$ 304.1
Enserco Facility	May 7, 2012	$ 250.0	$ —	$ 166.9	$ 83.1

Working Capital

The most significant items impacting working capital are our capital expenditures, the purchase of natural gas for our regulated Gas Utilities, payment of dividends to shareholders and funding energy marketing activities. 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 a combination of credit capacity available under our corporate revolver and cash on hand to meet our peak winter working capital requirements.

Our Energy Marketing segment engages in trading activities which carry working capital requirements, notably natural gas storage. The level of these requirements varies depending on market circumstances, marketing activities and counterparty liquidity requirements. In addition, Enserco's Credit Facility contains working capital requirements for each borrowing base election level.

Credit Facilities and Long-Term Debt

Revolving Credit Facility

On April 15, 2010, we terminated our $525 million Corporate Credit Facility and entered into a new $500 million Revolving Credit Facility expiring April 14, 2013. The new facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the new facility to $600 million and can be used for the issuance of letters of credit, to fund working capital needs and for other corporate purposes. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at December 31, 2010. The new facility contains a commitment fee to be charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.5%.

The 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) consolidated net worth in an amount of not less than the sum of $625 million and 50% of our aggregate consolidated net income, if positive, beginning January 1, 2005 and (ii) a recourse leverage ratio not to exceed 0.65 to 1.00. 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. We were in compliance with the covenants at December 31, 2010.

Our consolidated net worth was $1,100.3 million at December 31, 2010, which was approximately $241.0 million in excess of the net worth we were required to maintain under the credit facility. At December 31, 2010, our long-term debt ratio was 51.9%, our total debt leverage ratio (long-term debt and short-term debt) was 56.7%, and our recourse leverage ratio was approximately 57.5%.

Our ratios are calculated as required under the Revolving Credit Facility. Our consolidated net worth requirement is calculated by taking $625 million plus 50% of the net income, if positive, of the Company since January 1, 2005. Our long-term debt ratio is the ratio of our long-term debt over long-term debt plus our net worth. Our total debt leverage ratio is the same as our long-term debt ratio with the addition of current maturities of long-term debt and notes payable in the calculation. Our recourse leverage ratio is the ratio of our recourse debt, letters of credit (except letters of credit issued by our marketing subsidiary up to $250 million) and guarantees issued over our total capital which includes the balance in the numerator plus our net worth.

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 $35 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 Credit Facility

In May 2010, Enserco entered into an agreement for a two-year, $250 million committed credit facility. The facility includes a $100 million accordion feature which allows Enserco, with the consent of the administrative agent, to increase commitments under the facility. Societe Generale and BNP Paribas are co-lead arranger banks. The Bank of Tokyo Mitsubishi UFJ, Raiffeisen-Boerenleenbank BA (Rabobank), Credit Agricole, RZB Finance LLC and U.S. Bank are participating banks. This Enserco Credit Facility replaced the $300 million credit facility which expired on May 7, 2010. Maximum borrowings under the facility are subject to a sublimit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%. Enserco was in compliance with its covenants as of December 31, 2010.

In September 2010, the Enserco Credit Facility was amended to allow for trading of electric power, renewable energy credits and emissions credits.

Corporate Term Loan

In December 2010, we entered into a $100.0 million one-year term loan (the "Loan") with J.P. Morgan and Union Bank due in December 2011. The cost of the borrowings under the Loan is based on a spread of 137.5 basis points over LIBOR (which equates to 1.6875% at December 31, 2010). Borrowings under the Loan may be prepaid without penalty. The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as under the Revolving Credit Facility.

$200 Million Debt Offering

In July 2010, pursuant to a public offering, we issued $200.0 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Deferred financing costs of $1.7 million are being amortized over the 10-year term of the debt. Amortization of deferred financing costs is included in interest expense. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and to reduce issued letters of credit.

Black Hills Power

In February 2010, the Black Hills Power Series 8.06% AC bonds matured. These were paid in full for $30.0 million of principal plus accrued interest of $1.2 million.

In March 2010, Black Hills Power completed redemption of its Series Y 9.49% bonds in full. The bonds were originally due in 2018. A total of $2.7 million was paid on March 31, 2010, which includes the principal balance of $2.5 million plus accrued interest and an early redemption premium of 2.618%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheet and is being amortized over the remaining term of the original bonds.

In June 2010, Black Hills Power completed redemption of its Series Z 9.35% bonds in full. The bonds were originally due in 2021. A total of $21.8 million was paid on June 1, 2010, which included the principal balance of $20.0 million plus accrued interest and an early redemption premium of 4.675%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheet and is being amortized over the remaining term of the original bonds.

In October 2009, we completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par and a reoffer yield of 6.13%. The bonds mature November 1, 2039 and carry an annual interest rate of 6.125%, which is scheduled to be paid semi-annually. We received proceeds net of underwriting fees of $178.3 million which were used to repay intercompany borrowings under the Utility Money Pool agreement, primarily incurred to fund the construction of Wygen III and repayment of bonds. Deferred financing costs of approximately $2.2 million were capitalized and are being amortized over the term of the bonds.

Industrial Development Revenue Bonds

In September 2009, Cheyenne Light completed a $17 million weekly variable rate refunding bond issuance. The new issue replaced existing debt and converted the bond credit support structure from an AMBAC Financial Group insurance policy to a direct-pay letter of credit issued by Wells Fargo Bank. Laramie County, Wyoming was the tax-exempt conduit issuer for this transaction. The bonds were issued in two series: a $10.0 million series maturing March 1, 2027, and a $7.0 million series maturing September 1, 2021. The principal amounts and maturity dates did not change from the original financing. Including the letter of credit fees and other issuance costs, the current all-in rate as of December 31, 2010, was approximately 2.77%.

Under the terms of an agreement with the letter of credit provider, Cheyenne Light is required to maintain a debt to capitalization ratio of no more than 0.60 to 1.00 and an interest coverage ratio greater than or equal to 2.50 to 1.00. If Cheyenne Light fails to meet these covenants, subject to a 30-day cure period, it would constitute an event of default and the bank would have the right to cause the bonds and related outstanding obligations to become immediately due and payable. As of December 31, 2010, Cheyenne Light's capitalization and interest coverage ratios, calculated in accordance with the agreement, were 0.42 to 1.0 and 5.3 to 1.0, respectively. Cheyenne Light was in compliance with the requirements at December 31, 2010.

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. During 2009, we repaid the Acquisition Facility with proceeds of $30.2 million from the sale of 25% of the Wygen III plant to MDU, net proceeds from the $250 million public debt offering, and a borrowing of $104.6 million on our Corporate Credit Facility.

Black Hills Wyoming Project Financing

In December, 2009, our subsidiary Black Hills Wyoming issued $120.0 million in project financing debt. The loan amortizes over a seven-year term and matures on December 9, 2016, at which time the remaining balance of $78.8 million is due. Principal and interest payments are made on a quarterly basis with the scheduled principal payments based on projected cash flows available for debt service. Additional quarterly principal payments are required based upon actual cash flows available for debt service. Interest is charged at LIBOR plus 3.25% (3.54% at December 31, 2010). Proceeds were used to repay borrowings on the Corporate Credit Facility. Deferred financing costs were capitalized and are being amortized over the term of the debt. Black Hills Non-regulated Holdings, the Parent of Black Hills Wyoming, must maintain minimum equity of $100.0 million as a covenant of the financing. We were in compliance with this requirement at December 31, 2010.

Our Black Hills Wyoming project financing is secured by our ownership interest in the Wygen I plant and by the Gillette CT plant. The financing places restrictions on dividends or the loaning of funds by Black Hills Wyoming, which are permitted only in limited circumstances when cash flows for the projects exceed project debt service and reserve requirements.

Interest Rate Swaps

We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations. We have interest rate swaps with a notional amount of $250.0 million that are not designated as hedge instruments. Accordingly, mark-to-market changes in value on the swaps are recorded within the income statement. For the year ended December 31, 2010, we recorded a $15.2 million pre-tax unrealized mark-to-market non-cash loss on the swaps. For the year ended December 31, 2009, we recorded a $55.7 million pre-tax unrealized mark-to-market non-cash gain on the swaps. The mark-to-market value on these swaps was a liability of $54.0 million at December 31, 2010. Subsequent mark-to-market adjustments could have a significant impact on our results of operations. A one basis point move in the interest rate curve over the term of the swaps would have a pre-tax impact of approximately $0.3 million. These swaps are for terms of eight and 18 years and have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011. We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the stated termination dates.

In addition, we have $150.0 million notional amount floating-to-fixed interest rate swaps, having a maximum term of 6 years. These swaps have been designated as cash flow hedges and accordingly, their mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets. The mark-to-market value of these swaps was a liability of $21.8 million at December 31, 2010.

Cross-Default Provisions

Our Revolving Credit Facility contains 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 $35 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 $35 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, our Revolving Credit Facility 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 $35 million or more.

Forward Equity Transaction

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of $28.70875 per share.

On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares. In conjunction with the underwriters' exercise of the 413,519 share over-allotment option, an additional Equity Forward Agreement was entered into with J.P. Morgan for the over-allotment shares, having the same terms as the original Forward Agreement (together with the Forward Agreement, the "Forward Agreements").

The forward price used to determine cash proceeds due Black Hills Corporation at settlement of the equity forward instruments will be calculated based on the November 2010 public offering price of our common stock of $29.75 per share, adjusted for underwriting fees, interest rate adjustments as specified in the Forward Agreement, and expected dividends on our common stock during the period the instrument is outstanding. We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle at any date up to maturity, for all or a portion of the equity forward shares.

The equity forward instrument held by J.P. Morgan, underlying the Forward Agreements, was accounted for as equity in accordance with accounting for Derivatives and Hedging - Contracts in Entity's Own Equity, and recorded at fair value at the execution of the Forward Agreements, and will not be subsequently adjusted for changes in fair value until settlement. Since the initial pricing of the equity forward instrument of $28.70875 per share was determined based on the November 2010 offering price of our common stock of $29.75 per share, less underwriting fees of $1.04 per share, no premium on the transaction was due J.P. Morgan related to the Forward Agreements at execution, and no fair value was recorded to equity for the instrument. Proceeds or payments due at settlement of all or portions of the equity forward instrument will be recorded with appropriate adjustments to additional paid in capital and common stock, depending on the method of settlement.

At December 31, 2010, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $125.1 million. Assuming required notices were given and actions taken, the forward instruments could have also been cash or net settled at December 31, 2010 with respective delivery of cash of approximately $8.8 million or approximately 291,000 shares of common stock to J.P. Morgan.

The use of a forward sale agreement allowed us to avoid equity market uncertainty by pricing a stock offering under the current market conditions, while mitigating share dilution by postponing the issuance of stock until funds are needed. Underwriting discount fees totaled $4.6 million which will be deducted from the proceeds upon settlement.

Collateral

We had posted with counterparties the following amounts of collateral in the form of cash or letters of credit at December 31 (in thousands):

	2010	2009
Trading positions (energy marketing)	$ 170,260	133,805
Utility cash collateral requirements	10,355	3,789
Letters of credit on Revolving Credit Facility	46,865	44,752
Total Funds on Deposit	$ 227,480	$ 182,346

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.

At our Gas Utilities and Energy Marketing segments, 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.

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 the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (3.01% at December 31, 2010). 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 money pool balances included (in thousands):

	Borrowings From (Loans To) Money Pool Outstanding	
	2010	2009
Subsidiary:		
Black Hills Utility Holdings	$ 168,867	$ 128,357
Black Hills Power	$ (39,454)	$ (59,309)
Cheyenne Light	$ (14,527)	$ (1,182)
Total Money Pool borrowings from Parent	$ 114,886	$ 67,866

Registration Statements

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. Our current automatic shelf registration expires on May 6, 2011. 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, 2010, we had approximately 39.3 million shares of common stock outstanding, and no shares of preferred stock outstanding. In addition, pursuant to the Forward Agreements, we expect to issue an additional 4,413,519 shares of common stock on or prior to the November 10, 2011 maturity date.

Anticipated Financing Plans

We have substantial capital expenditures projected in 2011, primarily due to the construction of additional utility and IPP generation to serve our Colorado Electric Utility. Our capital requirements are expected to be financed through a combination of operating cash flows, borrowings on our Revolving Credit Facility and long-term financings. We may complete an additional long-term senior unsecured debt financing at the holding company level in 2011. We intend to maintain a consolidated debt-to-capitalization level in the range of 50% to 55%; however, during the construction period of our new generation facilities in Colorado, we may exceed this level on a temporary basis. We expect to complete a portion of the permanent financing through the settlement of the Forward Equity Agreement in order to maintain our target debt-to-capitalization level. We do not currently anticipate any difficulty accessing debt or equity markets.

Factors Influencing Liquidity

Many of our operations are subject to seasonal and market-driven fluctuations in cash flow. We have traditionally sourced variations in the working capital needs of our subsidiaries with cash on hand and capacity available under our credit facilities, and have sourced the capital expenditures of our subsidiaries through a combination of internally generated cash, equity contributions and borrowings by 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 has led to increased variability in our liquidity needs.

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.

Due to market conditions, the funding status of our pension plans is subject to multiple variables, many of which are beyond our control, including 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 2011 and future periods, which could materially affect our liquidity and results of operations.

Dividend Restrictions

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result of certain statutory limitations or regulatory or financing agreements, we could have restrictions on the amount of distributions allowed to be made by our subsidiaries.

Our credit facilities and other debt obligations 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 of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of December 31, 2010, we were in compliance with these covenants.

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. Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans. Additionally, our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2010, the restricted net assets at our Electric and Gas Utilities were approximately $196.8 million.

Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to its parent company. Enserco's restricted net assets at December 31, 2010 were $93.0 million compared to $205.8 million at December 31, 2009. Covenant changes under the new Enserco Credit Facility allowed for a reduction in capital investments in Enserco of more than $40 million in 2010.

As a covenant of the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. In addition, Black Hills Wyoming holds $4.3 million of restricted cash associated with the project financing requirements. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming.

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, 2010, 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, 2010 as follows:

Rating Agency	Rating	Outlook
Moody's	A3	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

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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 by approximately $1.0 million pre-tax based on our December 31, 2010 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 mark-to-market fair value.

Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2010	2009	2008
Acquisition costs:			
Payment for acquisition of net assets, net of cash acquired	$ —	$ —	$ 938,423 (1)
Property additions (2):			
Utilities -			
Electric Utilities	232,466 (3)	241,963 (3)	186,237 (3)
Gas Utilities	51,363	43,005	19,337 (4)
Non-regulated Energy -			
Oil and Gas	40,345	20,522	89,169 (5)
Power Generation	148,191 (6)	20,537 (6)	5,105
Coal Mining	17,053	11,765	25,190
Energy Marketing	390	220	22
Corporate	7,182	9,807	11,033
	496,990	347,819	336,093
Discontinued operations investing activities	—	—	29,836 (7)
Total expenditures for property, plant and equipment	496,990	347,819	1,304,352
Common stock dividends	56,467	55,151	53,663
Maturities/redemptions of long-term debt	59,926	2,173	130,297
Discontinued operations financing activities	—	—	73,928
	$ 613,383	$ 405,143	$ 1,562,240

(1) Cash paid for the Aquila properties, net of cash acquired.
(2) Includes accruals for property, plant and equipment.
(3) Includes (a) $13.1 million, $119.9 million, and $99.3 million for Wygen III construction in 2010, 2009, and 2008, respectively. During 2010 and 2009, we received reimbursement of $59.1 million and $58.0 million from the joint owners of the Wygen III facility. We own 52% of the Wygen III coal-fired plant that went into service on April 1, 2010; (b) $134.7 million and $48.1 million in 2010 and 2009, respectively for construction associated with our Colorado Electric Energy Resource Plan, including transmission and (c) $28.0 million, $21.1 million and $24.0 million in new transmission projects in 2010, 2009 and 2008, respectively.
(4) The Gas Utilities were acquired on July 14, 2008.
(5) Includes $16.9 million for acquisition of a non-operated interest in Wyoming in 2008.
(6) Includes $146.2 million and $16.4 million in 2010 and 2009, respectively for construction of two 100 MW natural gas-fired power generation facilities at Colorado IPP.
(7) Includes $27.8 million in 2008 for the construction of the Valencia plant, which was sold in the IPP Transaction.

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Forecasted Capital Expenditures

Forecasted capital requirements for maintenance capital and development capital are as follows (in thousands):

	2011	2012	2013
Regulated Utilities:			
Electric Utilities[1]	$ 197,600	$ 170,300	$ 138,900
Gas Utilities	65,200	55,800	47,600
Non-regulated Energy:			
Oil and Gas	48,900	61,500	93,300
Power Generation[2]	112,700	4,200	4,400
Coal Mining	12,500	16,000	16,700
Energy Marketing	2,400	3,400	3,400
Corporate	6,950	11,630	6,650
	$ 446,250	$ 322,830	$ 310,950

(1) Capital expenditures for our Electric Utilities include expenditures associated with our Colorado Electric Energy Resource Plan. The construction of two natural gas-fired combustion turbine facilities at Colorado Electric is expected to cost approximately $250 million to $260 million; construction is expected to be completed by the end of 2011. The planned expenditures included in this table reflect the mid-point of this range. We expect to spend approximately $67 million to $77 million in 2011 for this construction.

(2) Capital expenditures for our Power Generation segment include construction of two 100 MW natural gas-fired generation facilities at Black Hills Colorado IPP. The total construction cost is expected to be approximately $250 million to $260 million; construction is expected to be completed by the end of 2011. The planned expenditures included in this table reflect the mid-point of this range. We expect to spend approximately $87 million to $97 million in 2011 on this construction.

Contractual Obligations and Commitments

The following information is provided to summarize our cash obligations and commercial commitments at December 31, 2010. Actual future costs of estimated obligations may differ materially from these amounts.

Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
	Payments Due by Period (in thousands)				
Long-term debt[(a)(b)]	$ 1,191,420	$ 5,181	$ 231,446	$ 269,437	$ 685,356
Unconditional purchase obligations[(c)]	1,116,494	333,000	297,806	251,140	234,548
Operating lease obligations[(d)]	13,478	2,610	4,860	2,422	3,586
Other long-term obligations[(e)]	42,517	—	—	—	42,517
Employee benefit plans[(f)]	190,690	9,720	79,580	51,760	49,630
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions[(g)]	50,135	—	17,557	4,345	28,233
Notes Payable	249,000	249,000	—	—	—
Total contractual cash obligations[(h)]	$ 2,853,734	$ 599,511	$ 631,249	$ 579,104	$ 1,043,870

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

(b) The following amounts are estimated for interest payments on long-term debt over the next five years: $77.8 million in 2011, $77.6 million in 2012, $70.2 million in 2013, $51.3 million in 2014 and $39.7 million in 2015. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2010.

(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 PPA 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 2010 and price assumptions

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using existing prices at December 31, 2010. 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, 2010.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Oil and Gas, Coal Mining, Electric Utilities and Gas Utilities segments as discussed in Note 10 to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents estimated employer contributions to employee benefit plans through the year 2020.

(g) Years 1-3 include an estimated reversal of approximately $7.9 million associated with the gain deferred from the tax treatment related to the IPP Transaction and the Aquila Transaction. The income tax refund receivable was reversed as a result of an agreement reached with the IRS in 2010.

(h) Amounts in the above table exclude: (1) 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, 2010. These amounts have been excluded as it is impracticable to reasonably estimate the final amount and/or timing of any associated payments; and (2) contracts related to the construction of the 180 MW power generation facility by our Colorado Electric utility and 200 MW power generation facility by our Power Generation segment. We are in the process of procuring or have procured contracts for the turbines, building construction and labor. As of December 31, 2010, committed contracts for equipment purchases and for construction were 100% and 84% complete, respectively, for the Colorado Electric utility and 100% and 71% complete, respectively, for the Power Generation segment. Construction is expected to be completed at both facilities by December 31, 2011 with expenditures during 2011 of $67 million to $77 million for Colorado Electric and $87 million to $97 million for Black Hills Colorado IPP.

Dividends

Our dividend payout ratio for the year ended December 31, 2010, was 82% compared to 67% and 51% for the years ended December 31, 2009 and 2008, respectively. Dividends paid on our common stock totaled $1.44 per share in 2010, as compared to $1.42 per share in 2009 and $1.40 per share in 2008. Our three-year annualized dividend growth rate was 1.7%, and all dividends were paid out of available operating cash flows.

In January 2011, our Board of Directors declared a quarterly dividend of $0.365 per share or an annualized equivalent dividend rate of $1.46 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.

Off-Balance Sheet Arrangements

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2010, we had outstanding guarantees as indicated in the table below. Of the $116.5 million, $12.6 million was related to performance obligations under subsidiary contracts and $11.6 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

As of December 31, 2010, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2010	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2011
Guarantees for payment of obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP	7,134	2012
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	5,455	2012
Indemnification for subsidiary reclamation/surety bonds	11,564	Ongoing
Guarantee of payment obligations of Black Hills Utility Holdings for purchase of new office building	6,026	2011
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Black Hills Utility Holdings	9,300	2011
	$ 116,479	

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Cash Flow Activities

The following table summarizes our cash flows during 2010, 2009 and 2008 (in thousands):

		2010	2009	2008
Cash provided by (used in)				
Operating activities	$	147,752 $	270,502 $	145,641
Investing activities	$	(389,168) $	(269,823) $	(457,052)
Financing activities	$	160,953 $	(56,310) $	398,688

2010 Compared to 2009

Operating Activities:
Cash provided by operating activities of $147.8 million which was $122.8 million less than in 2009. Our operating cash flow decline was primarily attributable to:

- Cash earnings (net income plus adjustments to reconcile income) were consistent with prior year. Net income results were negatively impacted by mark-to-market losses in 2010 on interest rate swaps but positively impacted by mark-to-market gains on interest rate swaps in 2009, offset by a ceiling test impairment in 2009, which do not impact cash flows from operations;
- A $30.0 million contribution in 2010 to our defined benefit plans compared to $16.9 million in 2009;
- Outflows from operating assets and liabilities of $97.8 million as a result of:
  - Outflows from changes in accounts receivable primarily from an increase in our Energy Marketing receivables;
  - Materials, supplies and fuel used funds of $26.3 million primarily from the purchases of gas and oil by our Energy Marketing segment;
  - Inflows from changes in accounts payable and other current liabilities primarily from our Energy Marketing segment; and
  - Outflows of $23.9 million from higher use of funds in regulatory assets primarily related to energy efficiency rebates.

Investing Activities:
Cash used in investing activities was $389.2 million in 2010, which is $119.3 million more than in 2009. The increase primarily reflects higher capital additions partially offset by cash proceeds of $62.0 million for the sale of a portion of Wygen III to the City of Gillette. During 2010, cash outflows for property, plant and equipment additions totaled $472.7 million. Significant additions during 2010 included partial completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and on our 200 MW of natural gas-fired electric generation at Black Hills Colorado IPP, new transmission at the Electric Utilities, the completion of construction of Wygen III and oil and gas property maintenance capital and development drilling.

Financing Activities:
Cash provided by financing activities was $161.0 million in 2010, which was an increase of $217.3 million from 2009. During 2010, we issued $200.0 million in long-term debt and retired $59.9 million of long-term debt. During 2010, we paid $56.5 million of cash dividends on common stock.

2009 Compared to 2008

Operating Activities:
Cash provided by operating activities was $270.5 million in 2009, which was $124.9 million higher than in 2008. Our operating cash flow increase was primarily attributable to:

- Higher cash earnings of $28.6 million (net income plus adjustments to reconcile income). Operating results were impacted by mark-to-market changes on interest rate swaps which do not impact cash flows from operations;
- A $16.9 million contribution in 2009 to our defined benefit plans compared to $0.5 million in 2008;
- Inflows from operating assets and liabilities of $124.4 million as a result of:
  - Inflows from changes in accounts receivable primarily from our Energy Marketing receivables;
  - Materials, supplies and fuel used funds of $13.4 million primarily relating to natural gas held in storage by our Energy Marketing segment;
  - Outflows from changes in accounts payable and other current liabilities primarily from Energy Marketing; and
  - A $39.0 million increase in cash flows from changes in regulatory assets primarily related to deferred gas adjustments for our Gas Utilities.

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Investing Activities:
Cash used in investing activities was $269.8 million in 2009, which was $187.2 million lower than in 2008. The decrease resulted from an increase for capital additions in 2009, partially offset by cash proceeds in 2008 of $835.6 million from the sale of the IPP assets and the 2008 use of $938.4 million to purchase the Aquila assets. During 2009, cash outflows for property, plant and additions totaled $346.9 million. Significant additions during 2009 included Wygen III, partial completion of construction of 180 MW of natural gas-fired electric generation at Colorado Electric and 200 MW of natural-gas fired generation at Colorado IPP.

Financing Activities:
Cash used in financing activities was $56.3 million in 2009 compared to cash proceeds from financing activities in 2008 of $398.7 million. During 2009, we issued $543.1 million in long-term debt including proceeds of $248.5 million from the issuance of senior unsecured five year notes, proceeds of $180.0 million from the issuance of first mortgage bonds, and proceeds of $114.6 million from our Black Hills Wyoming project financing. Substantially all of the net proceeds were used to repay short-term borrowings and fund our capital additions. During 2009, we paid $55.2 million of cash dividends on common stock.

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 8 and 9 of our Notes to Consolidated Financial Statements; and
- Foreign currency exchange risk associated with our natural gas marketing business transacted in Canadian dollars.

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

To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. These policies have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, and employee conduct. 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.

Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in five states. All of our gas distribution utilities have PGA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to "true-up" billed amounts to match the actual natural gas cost we incurred. These adjustments are subject to periodic prudence reviews by the state utility commissions. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the PGAs for our regulated gas utilities. To the extent that our fuel and purchased power energy costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer.

As allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to volatility of natural gas prices. These transactions are considered derivatives and are marked-to-market. Gains or losses, as well as option premiums on these transactions, are recorded in Regulatory assets or Regulatory liabilities.

The fair value of our Gas Utilities derivative contracts are summarized below (in thousands):

		December 31, 2010		December 31, 2009
Net derivative liabilities	$	(7,188)	$	(1,511)
Cash collateral		10,355		3,789
	$	3,167	$	2,278

Trading Activities

Energy Marketing

We have a natural gas, crude oil, coal, power and environmental marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in 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, crude oil, coal, power and environmental products.

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 energy marketing business activities within the parameters as defined and allowed in the BHCRPP and further delineated in the energy 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, oil, coal, power and environmental 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, crude oil, coal, emissions credits and energy marketing and derivative commodity instruments at December 31, 2010 and 2009, are set forth in Note 3 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Fair Value of Energy Marketing Positions

The following table provides a reconciliation of activity in our marketing portfolio that has been recorded at fair value in accordance with GAAP during the year ended December 31, 2010 (in thousands):

Total fair value of energy marketing positions marked-to-market at December 31, 2009	$	19,521 [(a)]
Net cash settled during the period on positions that existed at December 31, 2009		(7,589)
Change in fair value due to change in assumptions		—
Unrealized gain on new positions entered during the period and still existing at December 31, 2010		16,766
Realized gain on positions that existed at December 31, 2009 and were settled during the period		(5,643)
Change in cash collateral		1,230
Unrealized loss on positions that existed at December 31, 2009 and still exist at December 31, 2010		(867)
Total fair value of energy marketing positions at December 31, 2010	$	23,418 [(a)]

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

	December 31, 2010	December 31, 2009
Net derivative assets	$ 28,524	$ 17,084
Cash collateral	3,958	2,728
Market adjustment recorded in material, supplies and fuel	(9,064)	(291)
Total fair value of energy marketing positions marked-to-market	$ 23,418	$ 19,521

To value the assets and liabilities for our outstanding derivative contracts, we use the fair value methodology outlined in accounting standards for fair value measurements and disclosures. See Note 4 of the Notes to Consolidated Financial Statements in this 2010 Annual Report on Form 10-K.

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

	Maturities		
Source of Fair Value	Less than 1 year	1 - 2 years	Total Fair Value
Level 1	$ —	$ —	$ —
Level 2	22,276	735	23,011
Level 3	3,188	2,325	5,513
Cash collateral	3,958	—	3,958
Market value adjustment for inventory (see footnote (a) above)	(9,064)	—	(9,064)
Total fair value of our energy marketing positions	$ 20,358	$ 3,060	$ 23,418

GAAP restricts mark-to-market accounting treatment primarily to those contracts that meet the definition of a derivative under accounting standards for derivatives and hedges. 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 marketing operations, we often employ strategies that include utilizing derivative contracts along with inventory, storage and transportation positions to accomplish the objectives of our marketing groups. Except in circumstances when we are able to designate transportation, storage or inventory positions as part of a fair value hedge, accounting standards for derivatives generally do 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. The table below references non-GAAP measures that quantify these positions.

The following table presents a reconciliation of our energy marketing positions recorded at fair value under GAAP to a non-GAAP measure of the fair value of our energy marketing forward book wherein all forward trading positions are marked-to-market (in thousands):

	December 31, 2010	December 31, 2009
Fair value of our energy marketing positions marked-to-market in accordance with GAAP (see footnote (a) above)	$ 23,418	$ 19,521
Market value adjustments for inventory, storage and transportation positions that are not marked-to-market under GAAP	(25,736)	(2,916)
Fair value of all forward positions (non-GAAP)	(2,318)	16,605
Cash collateral included in GAAP fair value	(3,958)	(2,728)
Fair value of all forward positions excluding cash collateral (non-GAAP)*	$ (6,276)	$ 13,877

* We consider this measure a Non-GAAP financial measure. This measure is presented because we believe it provides a more comprehensive view to our investors of our energy trading activities and thus a better understanding of these activities than would be presented by the GAAP measure alone.

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 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 90% 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 2011 and 2012 natural gas and crude oil production. The hedge agreements in place as of December 31, 2010 are as follows:

Natural Gas

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)		Price
CIG	1/26/2009	Swap	01/11 - 03/11	2,000	$	6.00
NWR	1/26/2009	Swap	01/11 - 03/11	2,000	$	6.05
San Juan El Paso	1/26/2009	Swap	01/11 - 03/11	5,000	$	6.38
San Juan El Paso	2/13/2009	Swap	01/11 - 03/11	2,500	$	6.16
AECO	3/4/2009	Swap	01/11 - 03/11	1,000	$	5.95
San Juan El Paso	6/2/2009	Swap	04/11 - 06/11	5,000	$	5.99
AECO	6/2/2009	Swap	04/11 - 06/11	800	$	5.89
NWR	6/2/2009	Swap	04/11 - 06/11	1,500	$	5.54
San Juan El Paso	6/25/2009	Swap	04/11 - 06/11	2,500	$	5.55
CIG	6/25/2009	Swap	04/11 - 06/11	1,750	$	5.33
CIG	9/2/2009	Swap	07/11 - 09/11	500	$	5.32
NWR	9/2/2009	Swap	07/11 - 09/11	500	$	5.32
San Juan El Paso	9/2/2009	Swap	07/11 - 09/11	2,500	$	5.54

Natural Gas (continued)

Location	Transaction Date	Hedge Type	Term	Volume (MMBtu/day)		Price
CIG	9/25/2009	Swap	07/11 - 09/11	500	$	5.59
NWR	9/25/2009	Swap	07/11 - 09/11	1,000	$	5.59
AECO	9/25/2009	Swap	07/11 - 09/11	500	$	5.76
San Juan El Paso	9/25/2009	Swap	07/11 - 09/11	5,000	$	5.91
San Juan El Paso	10/23/2009	Swap	10/11 - 12/11	2,500	$	6.23
NWR	10/23/2009	Swap	10/11 - 12/11	1,500	$	6.12
San Juan El Paso	10/23/2009	Swap	01/11 - 03/11	1,000	$	6.59
AECO	12/11/2009	Swap	10/11 - 12/11	500	$	6.27
CIG	12/11/2009	Swap	10/11 - 12/11	1,500	$	6.03
San Juan El Paso	12/11/2009	Swap	10/11 - 12/11	5,000	$	6.15
San Juan El Paso	1/8/2010	Swap	01/12 - 03/12	2,500	$	6.38
NWR	1/8/2010	Swap	01/12 - 03/12	1,500	$	6.47
AECO	1/8/2010	Swap	01/12 - 03/12	500	$	6.32
CIG	1/8/2010	Swap	01/12 - 03/12	1,500	$	6.43
San Juan El Paso	1/25/2010	Swap	01/12 - 03/12	5,000	$	6.44
San Juan El Paso	3/19/2010	Swap	07/11 - 09/11	500	$	5.19
San Juan El Paso	3/19/2010	Swap	04/12 - 06/12	7,000	$	5.27
CIG	3/19/2010	Swap	04/12 - 06/12	1,500	$	5.17
NWR	3/19/2010	Swap	04/12 - 06/12	1,500	$	5.20
AECO	3/19/2010	Swap	04/12 - 06/12	250	$	5.15
San Juan El Paso	6/28/2010	Swap	07/12 - 09/12	3,500	$	5.19
NWR	6/28/2010	Swap	07/12 - 09/12	1,500	$	5.01
CIG	6/28/2010	Swap	07/12 - 09/12	1,500	$	4.98

Crude Oil

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)		Price
NYMEX	1/26/2009	Swap	01/11 - 03/11	5,000	$	60.90
NYMEX	2/13/2009	Swap	01/11 - 03/11	5,000	$	60.05
NYMEX	3/4/2009	Swap	01/11 - 03/11	5,000	$	57.00
NYMEX	4/8/2009	Swap	04/11 - 06/11	5,000	$	68.80
NYMEX	4/23/2009	Swap	04/11 - 06/11	5,000	$	65.10
NYMEX	6/2/2009	Swap	01/11 - 03/11	5,000	$	75.05
NYMEX	6/2/2009	Swap	04/11 - 06/11	5,000	$	75.86
NYMEX	6/4/2009	Put	04/11 - 06/11	5,000	$	67.00
NYMEX	9/2/2009	Swap	07/11 - 09/11	5,000	$	75.10
NYMEX	9/2/2009	Put	07/11 - 09/11	5,000	$	63.00
NYMEX	9/29/2009	Swap	07/11 - 09/11	5,000	$	74.00
NYMEX	10/6/2009	Put	07/11 - 09/11	5,000	$	65.00
NYMEX	10/9/2009	Swap	10/11 - 12/11	5,000	$	79.35
NYMEX	10/23/2009	Put	10/11 - 12/11	5,000	$	75.00
NYMEX	11/19/2009	Swap	04/11 - 06/11	1,000	$	85.35
NYMEX	11/19/2009	Swap	07/11 - 09/11	1,500	$	85.95

Crude Oil (continued)

Location	Transaction Date	Hedge Type	Term	Volume (Bbls/month)		Price
NYMEX	11/19/2009	Swap	10/11 - 12/11	5,000	$	87.50
NYMEX	1/8/2010	Put	10/11 - 12/11	6,000	$	75.00
NYMEX	1/8/2010	Put	01/12 - 03/12	5,000	$	75.00
NYMEX	1/25/2010	Swap	01/12 - 03/12	5,000	$	83.30
NYMEX	2/26/2010	Swap	01/12 - 03/12	5,000	$	83.80
NYMEX	3/19/2010	Swap	01/12 - 03/12	5,000	$	83.80
NYMEX	3/19/2010	Swap	04/12 - 06/12	5,000	$	84.00
NYMEX	3/31/2010	Put	04/12 - 06/12	5,000	$	75.00
NYMEX	5/13/2010	Swap	04/12 - 06/12	5,000	$	87.85
NYMEX	6/28/2010	Swap	07/12 - 09/12	5,000	$	83.80
NYMEX	8/17/2010	Swap	04/12 - 06/12	3,000	$	82.60
NYMEX	8/17/2010	Swap	07/12 - 09/12	5,000	$	82.85
NYMEX	9/16/2010	Swap	07/12 - 09/12	5,000	$	84.60
NYMEX	11/9/2010	Swap	10/12 - 12/12	5,000	$	91.10

The hedge agreements entered into by the Company as of December 31, 2010 had a fair value of approximately $3.4 million as of December 31, 2010.

Wholesale Power

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, 2010, we had $150.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 6 years. These swaps have been designated as hedges in accordance with accounting standards for derivatives and hedges 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 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 it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during 2010 we recorded a $15.2 million pre-tax unrealized mark-to-market loss, in 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain to earnings, while in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are eight and 18 year swaps which have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011.

We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the stated termination dates.

Further details of the swap agreements are set forth in Note 3 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

On December 31, 2010 and 2009, our interest rate swaps and related balances were as follows (dollars in thousands):

December 31, 2010	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 %	6.0	$ —	$ —	$ 6,823	$ 14,976	$ (21,799)	$ —
Interest rate swaps	250,000	5.67 %	1.0	—	—	53,980	—	—	(15,193)
	$ 400,000			$ —	$ —	$ 60,803	$ 14,976	$ (21,799)	$ (15,193)
December 31, 2009									
Interest rate swaps	$ 150,000	5.04 %	7.00	$ —	$ —	$ 6,342	$ 9,075	$ (15,417)	$ —
Interest rate swaps	250,000	5.67 %	1.00	—	—	38,787	—	—	55,653
	$ 400,000			$ —	$ —	$ 45,129	$ 9,075	$ (15,417)	$ 55,653

Based on December 31, 2010 market interest rates and balances, a loss of approximately $6.8 million would be realized and reported in pre-tax earnings during the next twelve months. Estimated and realized losses will likely change during the next twelve months as market interest rates change.

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 (dollars in thousands):

	2011	2012	2013	2014	2015	Thereafter	Total
Long-term debt							
Fixed rate[(a)]	$ 162	$ 72	$ 225,000	$ 256,450	$ —	$ 577,200	$ 1,058,884
Average interest rate	13.66 %	13.66 %	6.5 %	8.89 %	— %	6.27 %	6.96 %
Variable rate	$ 5,019	$ 2,401	$ 3,973	$ 6,023	$ 6,964	$ 108,156	$ 132,536
Average interest rate	3.54 %	3.54 %	3.54 %	3.54 %	3.54 %	3.11 %	3.19 %
Total long-term debt	$ 5,181	$ 2,473	$ 228,973	$ 262,473	$ 6,964	$ 685,356	$ 1,191,420
Average interest rate	3.86 %	3.83 %	6.45 %	8.77 %	3.54 %	5.77 %	6.54 %

(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 Black Hills Corporation Credit Policy 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, 2010, approximately 75% of our credit exposure (exclusive of retail customers of our regulated utilities) 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 energy 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, 2010, we had outstanding forward exchange contracts to purchase approximately $15.0 million Canadian dollars. These contracts had a fair value of $(0.1) million at December 31, 2010. At December 31, 2009, we had no outstanding forward exchange contracts.

New Accounting Pronouncements

See Note 2 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2010 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, 2010, 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, 2010.

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, 2010. 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, 2010, 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.

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, 2010, 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 schedules as of and for the year ended December 31, 2010, of the Company and our report dated February 25, 2011, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's change in an accounting principle.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 25, 2011

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, 2010 and 2009, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, the Company changed certain items related to its oil and gas operations in 2009.

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, 2010, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 25, 2011

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended	December 31, 2010	December 31, 2009	December 31, 2008
	(in thousands, except per share amounts)		
Revenues:			
Utilities	$ 1,120,721	$ 1,100,204	$ 749,250
Non-regulated energy	186,530	169,374	256,540
Total revenues	1,307,251	1,269,578	1,005,790
Operating expenses:			
Utilities -			
Fuel, purchased power and cost of gas sold	626,528	652,725	448,411
Operations and maintenance	251,375	241,995	152,424
Non-regulated energy operations and maintenance	88,891	85,938	113,210
Gain on sale of operating assets	(8,921)	(25,971)	—
Depreciation, depletion and amortization	126,894	121,297	107,263
Impairment of long-lived assets	—	43,301	91,782
Taxes - property, production and severance	27,602	22,231	27,684
Other operating expenses	980	1,230	9,139
Total operating expenses	1,113,349	1,142,746	949,913
Operating income	193,902	126,832	55,877
Other income (expense):			
Interest charges -			
Interest expense (including amortization of debt expense, premiums and discounts, realized amount on interest rate swaps)	(107,790)	(90,878)	(58,252)
Allowance for funds used during construction - borrowed	10,689	5,839	2,811
Capitalized interest	4,381	349	1,318
Unrealized gain (loss) on interest rate swaps	(15,193)	55,653	(94,440)
Interest income	694	1,612	2,176
Allowance for funds used during construction - equity	2,996	5,891	3,835
Other expense	(176)	(513)	(187)
Other income	2,921	5,943	1,064
Total other income (expense)	(101,478)	(16,104)	(141,675)
Income (loss) from continuing operations before non-controlling interest and income taxes	92,424	110,728	(85,798)
Equity in earnings of unconsolidated subsidiaries	1,559	1,343	4,366
Income tax (expense) benefit	(25,298)	(33,315)	29,395
Income (loss) from continuing operations	68,685	78,756	(52,037)
Income from discontinued operations, net of income taxes	—	2,799	157,247
Net income	68,685	81,555	105,210
Net income attributable to non-controlling interest	—	—	(130)
Net income available for common stock	$ 68,685	$ 81,555	$ 105,080
Earnings (loss) per share of common stock:			
Basic -			
Continuing operations	$ 1.76	$ 2.04	$ (1.37)
Discontinued operations	—	0.07	4.12
Total	$ 1.76	$ 2.11	$ 2.75
Diluted -			
Continuing operations	$ 1.76	$ 2.04	$ (1.37)
Discontinued operations	—	0.07	4.12
Total	$ 1.76	$ 2.11	$ 2.75
Weighted average common shares outstanding:			
Basic	38,916	38,614	38,193
Diluted	39,091	38,684	38,193

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

FORM 10K

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

As of		December 31, 2010	December 31, 2009
		(in thousands, except share amounts)	
ASSETS			
Current assets:			
Cash and cash equivalents	$	32,438 $	112,901
Restricted cash		4,260	17,502
Accounts receivable, net		328,811	274,489
Materials, supplies and fuel		139,677	123,322
Derivative assets, current		56,572	37,747
Income tax receivable		—	2,031
Deferred income taxes, net		17,113	4,523
Regulatory assets, current		66,429	25,085
Other current assets		25,571	27,270
Total current assets		670,871	624,870
Investments		17,780	18,524
Property, plant and equipment		3,359,762	2,975,993
Less accumulated depreciation and depletion		(864,329)	(815,263)
Total property, plant and equipment, net		2,495,433	2,160,730
Other assets:			
Goodwill		354,831	353,734
Intangible assets, net		4,069	4,309
Derivative assets, non-current		9,260	3,777
Regulatory assets, non-current		138,405	135,578
Other assets		20,860	16,176
Total other assets		527,425	513,574
TOTAL ASSETS	$	3,711,509 $	3,317,698
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$	279,069 $	229,352
Accrued liabilities		170,301	151,504
Derivative liabilities, current		79,167	57,166
Accrued income tax		779	—
Regulatory liabilities, current		3,943	7,092
Notes payable		249,000	164,500
Current maturities of long-term debt		5,181	35,245
Total current liabilities		787,440	644,859
Long-term debt, net of current maturities		1,186,050	1,015,912
Deferred credits and other liabilities:			
Deferred income taxes, non-current		277,136	262,034
Derivative liabilities, non-current		21,361	11,999
Regulatory liabilities, non-current		84,611	42,458
Benefit plan liabilities		124,709	140,671
Other deferred credits and other liabilities		129,932	114,928
Total deferred credits and other liabilities		637,749	572,090
Commitments and contingencies (See Notes 3, 8, 9, 10, 13, 18, 19 and 20)			
Stockholders' equity:			
Common stock equity-			
Common stock $1 par value; 100,000,000 shares authorized; issued: 39,280,048 shares at 2010 and 38,977,526 shares at 2009		39,280	38,978
Additional paid-in capital		598,805	591,390
Retained earnings		486,075	473,857
Treasury stock at cost - 10,962 shares at 2010 and 8,834 shares at 2009		(309)	(224)
Accumulated other comprehensive loss		(23,581)	(19,164)
Total stockholders' equity		1,100,270	1,084,837
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$	3,711,509 $	3,317,698

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

FORM 10K

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2010	December 31, 2009	December 31, 2008
		(in thousands)	
Operating activities:			
Net income	$ 68,685	$ 81,555	$ 105,210
(Income) from discontinued operations, net of tax	—	(2,799)	(157,247)
Income (loss) from continuing operations	68,685	78,756	(52,037)
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities -			
Depreciation, depletion and amortization	126,894	121,297	107,263
Impairment of long-lived assets	—	43,301	91,782
Gain on sale of operating assets	(8,921)	(25,971)	—
Stock compensation	5,849	3,983	2,657
Unrealized mark-to-market (gain) loss on interest rate swaps	15,193	(55,653)	94,440
Earnings of associated companies	(1,559)	(1,343)	(2,581)
Allowance for funds used during construction - equity	(2,996)	(5,891)	(3,835)
Derivative fair value adjustments	10,873	27,362	(36,847)
Deferred income taxes	19,206	39,743	2,058
Employee benefit plans	16,342	16,349	7,779
Other adjustments	(3,218)	4,036	6,720
Change in operating assets and liabilities-			
Materials, supplies and fuel	(25,265)	1,078	14,525
Accounts receivable and other current assets	(51,443)	78,886	(50,955)
Accounts payable and other current liabilities	30,772	(53,157)	(21,453)
Regulatory assets	(21,283)	2,598	(36,400)
Regulatory liabilities	50	1,265	526
Contributions to defined pension plans	(30,015)	(16,945)	(500)
Other operating activities	(1,412)	7,892	4,446
Net cash provided by operating activities of continuing operations	147,752	267,586	127,588
Net cash provided by operating activities of discontinued operations	—	2,916	18,053
Net cash provided by operating activities	147,752	270,502	145,641
Investing activities:			
Property, plant and equipment additions	(472,681)	(346,872)	(328,922)
Payment for acquisition of net assets, net of cash acquired	(2,250)	—	(938,423)
Proceeds from sale of business operations	—	—	835,592
Proceeds from sale of assets	70,357	84,661	—
Working capital adjustment - Aquila Transaction	—	7,880	—
Other investing activities	15,406	(15,492)	4,537
Net cash used in investing activities of continuing operations	(389,168)	(269,823)	(427,216)
Net cash used in investing activities of discontinued operations	—	—	(29,836)
Net cash used in investing activities	(389,168)	(269,823)	(457,052)
Financing activities:			
Dividends paid on common stock	(56,467)	(55,151)	(53,663)
Common stock issued	3,246	4,819	2,683
Decrease in short-term borrowings	(770,000)	(1,125,300)	(483,500)
Increase in short-term borrowings	854,500	586,000	1,150,300
Long-term debt - issuance	200,000	543,069	—
Long-term debt - repayments	(59,926)	(2,173)	(130,297)
Other financing activities	(10,400)	(7,574)	(12,907)
Net cash provided by (used in) financing activities of continuing operations	160,953	(56,310)	472,616
Net cash used in financing activities of discontinued operations	—	—	(73,928)
Net cash provided by (used in) financing activities	160,953	(56,310)	398,688
Net change in cash and cash equivalents	(80,463)	(55,631)	87,277
Cash and cash equivalents beginning of year	112,901	168,532	81,255
Cash and cash equivalents end of year	$ 32,438	$ 112,901	$ 168,532

See Note 16 for supplemental disclosure of cash flow information

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 CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in thousands except share amounts)	Common Stock		Treasury Stock					
	Shares	Value	Shares	Value	Additional Paid in Capital	Retained Earnings	AOCI	Total
Balance at December 31, 2007	37,842,221	$ 37,842	45,916	$ (1,347)	$ 560,475	$ 397,393	$ (24,508)	$ 969,855
Net income available for common stock	—	—	—	—	—	105,080	—	105,080
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	5,725	5,725
Dividends on common stock	—	—	—	—	—	(53,663)	—	(53,663)
Share-based compensation	207,461	207	(5,733)	(45)	3,423	—	—	3,585
Tax effect of share-based compensation	—	—	—	—	432	—	—	432
Stock issued under earn-out litigation	593,804	594	—	—	19,100	—	—	19,694
Other stock transactions	32,568	33	—	—	1,152	—	—	1,185
Cumulative effect of change in accounting principle	—	—	—	—	—	(1,357)	—	(1,357)
Balance at December 31, 2008	38,676,054	$ 38,676	40,183	$ (1,392)	$ 584,582	$ 447,453	$ (18,783)	$ 1,050,536
Net income available for common stock	—	—	—	—	—	81,555	—	81,555
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(381)	(381)
Dividends on common stock	—	—	—	—	—	(55,151)	—	(55,151)
Share-based compensation	158,140	159	(31,349)	1,168	4,830	—	—	6,157
Tax effect of share-based compensation	—	—	—	—	(120)	—	—	(120)
Dividend reinvestment and stock purchase plan	143,332	143	—	—	2,098	—	—	2,241
Balance at December 31, 2009	38,977,526	$ 38,978	8,834	$ (224)	$ 591,390	$ 473,857	$ (19,164)	$ 1,084,837
Net income available for common stock	—	—	—	—	—	68,685	—	68,685
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(4,417)	(4,417)
Dividends on common stock	—	—	—	—	—	(56,467)	—	(56,467)
Share-based compensation	195,915	196	2,128	(85)	4,706	—	—	4,817
Tax effect of share-based compensation	—	—	—	—	(33)	—	—	(33)
Equity forward	—	—	—	—	(288)	—	—	(288)
Dividend reinvestment and stock purchase plan	106,231	106	—	—	3,035	—	—	3,141
Other stock transactions	376	—	—	—	(5)	—	—	(5)
Balance at December 31, 2010	39,280,048	$ 39,280	10,962	$ (309)	$ 598,805	$ 486,075	$ (23,581)	$ 1,100,270

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

For the year ended	December 31, 2010	December 31, 2009	December 31, 2008
	(in thousands)		
Comprehensive income:			
Net income	$ 68,685	$ 81,555	$ 105,210
Other comprehensive (loss) income, net of tax (see Note 15)	(4,417)	(381)	5,725
Less: Net income attributable to non-controlling interest	—	—	(130)
Consolidated comprehensive income	$ 64,268	$ 81,174	$ 110,805

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

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2010, 2009 and 2008

(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 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 all doing business as Black Hills Energy.

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 exploration and production activities. Power Generation, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities. Coal Mining, which is conducted through WRDC, engages in coal mining activities. Energy Marketing, which is conducted through Enserco, engages in marketing natural gas, crude oil, coal, power and environmental products. These businesses are aggregated for reporting purposes as Non-regulated Energy.

For further descriptions of our reportable business segments, see Note 17.

On July 14, 2008, we completed the acquisition of an electric utility in Colorado and 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 these acquired utilities are included in our Consolidated Financial Statements. See Note 23 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 22 for additional information.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain 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 significant accounting policies that we believe include management estimates that are critical in understanding our financial results relate to market value of derivatives, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, actuarially determined employee benefit costs, valuation of deferred taxes and contingencies. Actual results could differ materially from those estimates.

Certain prior years' data presented in the financial statements has been reclassified to conform to the current year presentation. The format of the consolidated statements of income for the prior periods has been modified to reflect the retrospective application of a change in the presentation of the statement of income. This change was made to enhance our statement of income presentation to reflect our segment reporting. Additionally, the consolidated statements of cash flows for the years ended December 31, 2009 and 2008 have been modified within the "Net cash provided by operating activities" to display the amounts of non-cash "Employee benefit plan" activity and cash "Contributions to defined benefit plans" previously recorded within "Other operating activities."

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned subsidiaries. Generally, we use the equity method of accounting for investments in 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 ASC 805-10. 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 energy and fuel sales, and shared assets in accordance with accounting standards for regulated operations. For additional information on intercompany revenues, see Note 17.

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, the Wygen I power plant, the Wygen III power plant, and the BHEP gas processing plant. See Note 7 for additional information.

Cash Equivalents

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

Restricted Cash

The Black Hills Wyoming project financing, completed in December 2009, requires that cash accounts are maintained for various specified purposes. We do not readily have access to these accounts and can only withdraw funds upon meeting certain requirements. Therefore, we have classified these amounts as restricted cash.

Accounts Receivable and Allowance for Doubtful Accounts

We maintain an allowance for doubtful accounts which reflects our best estimate of potentially uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectability.

Accounts receivable for our Utilities Group consists of sales to residential, commercial, industrial, municipal and other customers all of which do not bear interest. These accounts receivable are stated at billed amounts net of write-offs or payment received. Approximately 18% of the accounts receivable balance consists of unbilled revenue.

Accounts receivable for our Non-regulated Energy Group consists of amounts due from sales of coal, oil and gas, and from our trading activities. Our Energy Marketing segment utilizes master netting agreements which is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of 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.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

Following is a summary of accounts receivable as of December 31 (in thousands):

2010	Accounts Receivable, Trade	Unbilled Revenues	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$ 51,005	$ 19,572	$ 70,577	$ (708)	$ 69,869
Gas	41,970	40,376	82,346	(1,425)	80,921
Oil and Gas	6,213	—	6,213	(161)	6,052
Coal Mining	2,420	—	2,420	—	2,420
Energy Marketing	157,064	—	157,064	(69)	156,995
Power Generation	307	—	307	—	307
Corporate	12,247	—	12,247	—	12,247
Total	$ 271,226	$ 59,948	$ 331,174	$ (2,363)	$ 328,811

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2009	Accounts Receivable, Trade	Unbilled Revenues	Total Accounts Receivable	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric	$ 43,497	$ 15,014	$ 58,511	$ (1,227)	$ 57,284
Gas	39,962	46,373	86,335	(2,456)	83,879
Oil and Gas	5,687	—	5,687	—	5,687
Coal Mining	1,493	—	1,493	—	1,493
Energy Marketing	123,322	—	123,322	(938)	122,384
Power Generation	585	—	585	—	585
Corporate	3,177	—	3,177	—	3,177
Total	$ 217,723	$ 61,387	$ 279,110	$ (4,621)	$ 274,489

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 the 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 in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

In addition, in accordance with accounting standards for derivatives and hedging, 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. All energy marketing contracts that do not meet the definition of a derivative have been accounted for under the accrual method of accounting.

We present our operating revenues from energy marketing operations in accordance with the accounting standards for energy trading contracts. Accordingly, gains and losses (realized and unrealized) on transactions at our energy marketing operations are presented on a net basis in operating revenues, whether or not settled physically.

For long-term power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition for regulated operations, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition for a regulated operation, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of (in thousands):

	December 31, 2010	December 31, 2009
Materials and supplies	$ 31,749	$ 31,535
Fuel - Electric Utilities	9,687	7,128
Natural gas in storage - Gas Utilities	21,691	24,053
Gas, oil and coal held by Energy Marketing*	76,550	60,606
Total materials, supplies and fuel	$ 139,677	$ 123,322

* As of December 31, 2010 and 2009, market adjustments related to gas held by Energy Marketing and recorded in inventory as part of fair value hedge transactions, were $(9.1) million and $(0.3) million, respectively.

Natural gas in storage at our regulated Gas Utilities primarily represents gas purchased for use by our customers and is valued at the weighted-average cost of the gas. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Gas, oil and coal 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. 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. See Note 3 for further discussion of Energy Marketing trading activities.

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 amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets.

AFUDC represents the approximate composite cost of borrowed funds and a return on equity used to finance a utility project. Capitalized interest is an offset to Interest expense on the accompanying Consolidated Statements of Income.

The amount of AFUDC and capitalized interest was as follows (in thousands):

Years ended	December 31, 2010	December 31, 2009	December 31, 2008
AFUDC - borrowed	$ 10,689	$ 5,839	$ 2,811
AFUDC - equity	$ 2,996	$ 5,891	$ 3,835
Capitalized interest	$ 4,381	$ 349	$ 1,318

The cost of regulated utility 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 related to our regulated properties 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, results in gains or losses recognized as a component of operating 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 based 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 reclamation 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.

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. These costs are generally expected to be included in costs to be amortized within the term of the underlying lease agreement which varies in length.

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 SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. Effective for the 2009 fiscal year end, a twelve month average price is calculated using the price at the first day of each month for each of the preceding twelve months.

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. No ceiling test write-downs were recorded in 2010.

As a result of lower natural gas prices at March 31, 2009, we recorded a non-cash ceiling test impairment of oil and gas long-lived assets included in the Oil and Gas segment. The lower prices at March 31, 2009 resulted in a $43.3 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 properties was recorded as Impairment of long-lived assets and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Also, at December 31, 2008, as a result of low crude oil and natural gas prices, we recorded a pre-tax non-cash ceiling test impairment of our oil and gas long-lived 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.

Goodwill and Intangible Assets

Under accounting standards for goodwill and intangible assets, goodwill and intangible assets with indefinite lives are not amortized but the carrying values are reviewed at least 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.

On July 14, 2008, we completed the acquisition of one regulated electric and four regulated gas utilities from Aquila. As of December 31, 2008, $344.5 million was recorded to goodwill for this transaction. Intangible assets represent easements, rights-of-way and trademarks and are amortized using a straight-line method using estimated useful lives of 20 years. Goodwill was adjusted for tax adjustments in 2010 in the amount of $0.8 million and for final working capital and tax adjustments during 2009 in the amount of $5.6 million. Final allocation of the purchase price included $339.0 million of goodwill and $4.9 million of intangible assets. Less than $0.1 million of the intangible assets have an indefinite life while the remaining amount of $4.8 million is being amortized over twenty years. Amortization expense for existing intangible assets is expected to be $0.2 million per year through 2015.

Changes to goodwill during the years ended December 31 relating to taxes, were as follows (in thousands):

	December 31, 2010	December 31, 2009	December 31, 2008
Beginning balance	$ 353,734	$ 359,290	$ 11,482
Additions (adjustments)	1,097	(5,556)	347,808
Ending balance	$ 354,831	$ 353,734	$ 359,290

Changes to intangible assets were as follows (in thousands):

	December 31, 2010	December 31, 2009	December 31, 2008
Beginning balance	$ 4,309	$ 4,884	$ 3
Additions (adjustments)	—	(365)	4,919
Amortization expense	(240)	(210)	(38)
Ending balance	$ 4,069	$ 4,309	$ 4,884

We performed our annual goodwill impairment tests during the fourth quarter. We estimated the fair value of the goodwill using discounted cash flow methodology and an analysis of comparable 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, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital, and long-term earnings and merger multiples for comparable companies. We believe that the goodwill amount reflects the value of the

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relatively stable, long-lived cash flows of the regulated gas utility business, considering the regulatory environment and market growth potential and the value of the significant rate base growth opportunities at our electric utility in Colorado.

Asset Retirement Obligations

We initially record liabilities for the present value of retirement costs for which we have 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 at the time of settlement. 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. Additional information is included in Note 10.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value, and that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly.

Accounting standards for derivatives and hedging require that the unrealized gains or losses on a derivative instrument designated and qualifying as a fair value hedging instrument as well as the offsetting unrealized loss or gain on the hedged item attributable to the hedged risk be recognized currently in earnings in the same accounting period. Conversely, the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument must 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.

Weather Hedges

As approved in the State of Iowa, Iowa Gas may use weather derivatives to mitigate the effect of fluctuations from normal weather, but not for trading or speculative purposes. Accounting standards for derivatives and hedging require that weather hedges are accounted for by the intrinsic value method which records an asset or liability for the difference between the actual and contracted threshold cooling or heating degree days in the period, multiplied by the contract price. Any gains or losses recorded on these contracts are recorded as regulatory assets or regulatory liabilities, respectively. Weather hedges were not purchased in 2010, and there was no weather hedge in place at December 31, 2010. Anticipated settlements for 2009 totaling $1.8 million are included in Accounts receivable, net on the accompanying Consolidated Balance Sheets as of December 31, 2009.

Currency Adjustments

Our functional currency for all operations is the United States dollar. Through Enserco, we engage in natural gas marketing 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. Gains or losses on currency transactions executed in Canadian dollars are recorded in Revenues, Non-regulated energy on the accompanying Consolidated Statements of Income as incurred.

Deferred Financing Costs

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

Development Costs

According to accounting standards for business combinations, we 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 Other operating expenses on the accompanying Consolidated Statements of Income.

Legal Costs

Litigation liabilities, including potential settlements, are recorded when it is both probable that a liability or settlement has been incurred, and the amount can be reasonably estimated. Legal costs related to ongoing litigation are expensed as incurred.

Non-controlling Interest

Under accounting standards for variable interest entities, we were considered the primary beneficiary of the agreement with Wygen Funding, LP to lease the Wygen I plant. Net income attributable to non-controlling interest in the accompanying Consolidated Statements of Income represents the non-affiliated equity investors' interest in Wygen Funding, L.P., a VIE. In June 2008, at the end of the lease term, we purchased the Wygen I plant.

Earnings attributable to minority ownership are shown on the accompanying Consolidated Statements of Income on a pre-tax basis as the entity with the non-controlling 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.

Our financial statements follow accounting standards for regulated operations and reflect the effects of the numerous rate-making 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. Our regulatory assets represent amounts for which we will recover the cost, but are not allowed a return. In the event we determine that Black Hills Power, Cheyenne Light, Iowa Gas, Nebraska Gas, Kansas Gas, Colorado Gas or Colorado Electric no longer meet the criteria for following accounting standards for regulated operations, the accounting impact to the Company could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities (in thousands):

	Recovery or Settlement Period	As of December 31, 2010	As of December 31, 2009
Regulatory assets			
Deferred energy and fuel costs adjustments - current	less than one year	$ 30,298	$ 30,590
Deferred gas cost adjustments and gas price derivatives	less than one year	39,407	11,496
AFUDC	Up to 45 years	13,391	13,935
Employee benefit plans	Up to 13 years	83,144	86,818
Environmental	Subject to approval	2,353	2,268
Asset retirement obligations	Up to 44 years	3,066	2,912
Bond issue cost	Through November 2037	3,847	3,990
Renewable energy standard adjustment	Up to 5 years	14,254	4,435
Flow through accounting	Up to 35 years	7,491	564
Other regulatory assets	Various	7,583	3,655
		$ 204,834	$ 160,663
Regulatory liabilities			
Deferred energy and gas costs	Less than one year	$ 1,200	$ 1,932
Employee benefit plans	Up to 13 years	36,155	—
Cost of removal	Up to 44 years	39,638	35,983
Revenue subject to refund	Less than one year	1,016	3,938
Other regulatory liabilities	Various	10,545	7,697
		$ 88,554	$ 49,550

Regulatory assets are primarily recorded for the probable future revenues to recover the costs associated with a 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.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers in excess of current rates and which will be recovered in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission.

Deferred Gas Cost Adjustment and Gas Price Derivatives - Our regulated gas utilities have PGA provisions that allow them to pass the cost of gas on 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. 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 file periodic estimates of future gas costs based on market forecasts.

AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset itself is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plans and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income.

Environmental - Environmental is associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement Obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 10 for additional details.

Bond Issue Costs - Bond issue costs are recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in a rate case settlement that was reached with respect to Black Hills Power in 2010. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment. A regulatory asset was established to reflect that future increases in taxes payable will be recovered from customers as the temporary differences reverse.

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

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

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirements.

Cost of Removal - 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 obligation for removal. Liabilities will be settled and trued up following completion of the related activities.

Revenues Subject To Refund - Revenues subject to refund represent a portion of the revenues collected from customers based on approved interim rates which are contingent on 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 nature of the related assets and liabilities.

We account for uncertainty in income taxes recognized in the financial statements in accordance with accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 14 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing operations is computed by dividing "Income (loss) from continuing operations" 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 (loss) from continuing operations and basic and diluted share amounts is as follows (in thousands):

	December 31, 2010		December 31, 2009		December 31, 2008	
	(Loss) Income	Average Shares	(Loss)Income	Average Shares	(Loss) Income	Average Shares
Basic - Income (loss) from continuing operations	$ 68,685	38,916	$ 78,756	38,614	$ (52,037)	38,193
Dilutive effect of:						
Stock options	—	14	—	—	—	—
Restricted stock	—	107	—	66	—	—
Equity forward instrument	—	29	—	—	—	—
Other dilutive effects	—	25	—	4	—	—
Diluted - Income (loss) from continuing operations	$ 68,685	39,091	$ 78,756	38,684	$ (52,037)	38,193

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):

	December 31, 2010	December 31, 2009	December 31, 2008
Options to purchase common stock	158	462	—
Restricted stock	1	3	4
Other	1	45	26
	160	510	30

Equity Forward Instrument

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 equity forward shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of $28.70875 per share.

On December 7, 2010, the underwriters exercised the over-allotment option for an additional 413,519 shares. The terms for the over-allotment shares are the same as the equity forward shares. Disclosures regarding the Forward Agreement are in Note 11.

(2) RECENTLY ADOPTED AND RECENTLY ISSUED ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

Disclosures About the Credit Quality of Financing Receivables and the Allowance for Credit Losses, ASC 310-10-50

In July 2010, the FASB issued an amendment to ASC 310-10-50, Receivables - Disclosures. The guidance requires additional disclosures that will facilitate a financial statement user's evaluation of the nature of credit risk inherent in financing receivables, how that risk is analyzed in arriving at the allowance for credit losses, and the reason for any changes in the allowance for credit losses. These disclosures should be provided on a disaggregated basis but exempts trade receivables that have a contractual maturity of one year or less, receivables measured at lower of cost or fair value, and receivables measured at fair value with the changes in fair value reported in earnings. The additional disclosures are presented in Note 1. The standard is effective for interim and annual reporting periods ending on or after December 15, 2010.

Fair Value Measurements and Disclosures, ASC 820

The ASC for Fair Value Measurements and Disclosures defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosure requirements related to fair value measurements. This does not expand the application of fair value accounting to any new circumstances, but applies the framework to other applicable GAAP that requires or permits 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 instruments, and other miscellaneous financial instruments.

In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements, disclosure of inputs and techniques used in valuation and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements are required to be presented separately. These disclosures are required for interim and annual reporting periods and were effective for us January 1, 2010, except the disclosures related to purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective January 1, 2011. The guidance requires additional disclosures, but did not impact our financial position, results of operations or cash flows. The additional disclosures are included in Note 4.

In accordance with the ASC for Fair Value Measurements, on January 1, 2008, 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 in 2008 that was recorded within our unrealized marketing margins. Unrealized margins are presented as a component of Revenues, Non-regulated energy on the accompanying Consolidated Statements of Income. Disclosures regarding the level of pricing observability associated with instruments carried at fair value are provided in Note 4.

Extractive Activities — Oil and Gas Reserves (SEC Release #33-8995), ASC 932-10-S99

The FASB issued an accounting standards update which aligns the oil and gas reserve estimation and disclosure requirements with the SEC released Final Rule, "Modernization of Oil and Gas Reporting" which amended 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 oil and gas prices used to determine reserves from the period-end price to a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months before the end of the reporting period. The amendment was effective for reporting periods ending on or after December 31, 2009. The implementation of this SEC requirement resulted in additional depletion expense of $1.3 million in the fourth quarter of 2009.

Consolidation of Variable Interest Entities, ASC 810-10-15

In June 2009, the FASB issued a revision regarding consolidations. The amendment requires a company to consider whether an entity that is insufficiently capitalized or is not controlled through voting should be consolidated. It requires additional disclosures about the involvement with variable interest entities and any significant changes in risk exposure due to that involvement. This standard is effective for annual periods that begin after November 15, 2009 with ongoing re-evaluation. The adoption of this standard in January 2010 did not have any impact on our consolidated financial position, results of operations, and cash flows.

Consolidation of Non-Controlling Interest, ASC 810

The ASC for Consolidation of Non-Controlling Interest establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the non-controlling interest, changes in a parent's ownership interest, and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The ASC establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. These standards and disclosure requirements were effective January 1, 2009.

Net income attributable to non-controlling interest in the accompanying Consolidated Statements of Income represents a non-affiliated equity investors' interest in Wygen Funding LP, a VIE. In June 2008, we purchased the non-controlling share retiring $128.3 million of Wygen I project debt. Presentation of a non-controlling interest that we held until June 2008 was retrospectively applied as required, and had an immaterial overall effect on our consolidated financial position, results of operations and cash flows.

Derivative and Hedging, ASC 815

Accounting standards for Derivatives and Hedging require enhanced disclosures about derivatives and hedging activities and their effect on an entity's financial position, financial performance and cash flows. Accounting standards for derivatives and hedging encourages, but does not require, disclosures for earlier periods presented for comparative purposes at initial adoption. Required disclosures for periods subsequent to January 1, 2009 are provided in Note 3 and Note 4.

Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, ASC 715

The ASC for Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans requires the recognition of the overfunded or underfunded status of defined benefit postretirement plans as an asset or liability in the statement of financial position, recognition of changes in the funded status in comprehensive income, measurement of the funded status of a plan as of the date of the year-end statement of financial position and provides for related disclosures. Effective for fiscal years ending after December 15, 2008, this accounting standard required the measurement of the funded status of the plan to coincide with the date of the year-end statement of financial position. Therefore, the measurement date for the funded status of our pension and other postretirement benefit plans was changed to December 31 in 2009 from September 30. ASC 715 also provides guidance on an employer's disclosure about plan assets for a defined benefit pension or other postretirement plans. These disclosures are effective for fiscal years ending after December 15, 2009. The additional disclosures are provided in Note 18.

Recently Issued Accounting Pronouncements and Legislation

Patient Protection and Affordable Care Act

In March 2010, the President of the United States signed into law comprehensive healthcare reform legislation under the PPACA as amended by the Healthcare and Education Reconciliation Act. The potential impact on the Company, if any, cannot be determined until regulations are promulgated under the PPACA. Included among the provisions of the PPACA is a change in the tax treatment of the Medicare Part D subsidy (the "subsidy") which affects our Non-Pension Postretirement Benefit Plan. Internal Revenue Code Section 139A has been amended to eliminate the deduction of the subsidy in reducing income for years beginning after December 31, 2012. The impact of this change in the tax treatment of the subsidy had an immaterial effect on our financial position, results of operations and cash flows. The Company will continue to assess the accounting implications of the PPACA as related regulations and interpretations become available.

Dodd-Frank Wall Street Reform and Consumer Protection Act

In July 2010, the President of the United States signed into law comprehensive financial reform legislation under Dodd-Frank. Title VII of Dodd-Frank effectively regulates many derivative transactions in the United States that were previously unregulated, including swap transactions in the over-the-counter market. Among other things, Dodd-Frank (i) mandates the clearing of some swaps through regulated central clearing organizations and the trading of clearing swaps through regulated exchanges or swap execution facilities, in each case subject to certain key exemptions, and (ii) authorizes regulators to establish collateral and margin requirements for certain swap transactions that are not cleared. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. Significant rule-making by numerous governmental agencies, particularly the CFTC with respect to non-security commodities, will be required over the next several months to implement the restrictions, limitations, and requirements contemplated by Dodd-Frank, and we will continue to evaluate the impact as these rules become available.

(3) RISK MANAGEMENT ACTIVITIES

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

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our marketing businesses, our natural long position with crude oil and natural gas reserves and production, fuel procurement for certain of our gas-fired generation assets and variability in revenue due to changes in gas usage at our regulated Gas Utilities segment resulting from commodity price changes;
- Interest rate risk associated with variable rate credit facilities and project financing floating rate debt as described in Notes 8 and 9; 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

Energy Marketing

We have a natural gas, crude oil, coal, power and environmental marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the United States and Canada.

Contracts and other activities at our energy marketing operations are accounted for under accounting standards for derivatives and hedging and energy trading contracts. As such, all of the contracts and other activities at our energy marketing operations that meet the definition of a derivative 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 Revenues, Non-regulated energy in the accompanying Consolidated Statements of Income. ASC 940-325-S99 precludes mark-to-market accounting for energy trading contracts that are not defined as derivatives. As part of our energy 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, accounting standards for derivatives and hedging generally do not allow us to mark inventory, transportation or storage positions to market. The result is that while a high percentage of our energy marketing positions are economically hedged, we are required to mark a portion 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 results from these accounting requirements.

To effectively manage our portfolios, we enter into forward physical commodity contracts, financial derivative instruments, including over-the-counter swaps and options and storage and transportation agreements. The business activities of our Energy Marketing segment are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the energy marketing Risk Management Policies and Procedures as approved by our Executive Risk Committee. Our contracts do not include credit risk-related contingent features.

We use a number of quantitative tools to measure, monitor and limit our exposure to market risk in our energy 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, storage, transportation and foreign exchange positions.

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 and terms of the natural gas, crude oil, coal and power marketing and derivative commodity instruments as of December 31 are set forth below:

	2010		2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Natural Gas (thousands of MMBtu):				
Natural gas basis swaps purchased	399,128	22	231,703	22
Natural gas basis swaps sold	426,903	22	232,673	22
Natural gas fixed-for-float swaps purchased	135,005	33	60,927	16
Natural gas fixed-for-float swaps sold	150,803	22	72,904	25
Natural gas physical purchases	144,948	36	120,680	27
Natural gas physical sales	143,021	36	124,830	27
Natural gas options purchased	—	—	—	—
Natural gas options sold	—	—	—	—
Crude Oil (thousands of Bbls):				
Crude oil physical purchases	5,628	16	5,048	12
Crude oil physical sales	6,921	16	4,998	12
Crude oil swaps purchased	20	3	—	—
Crude oil swaps sold	240	4	69	2

	2010	
	Notional Amounts	Latest Expiration (months)
Coal (thousands of tons): *		
Coal fixed-for-float swaps purchased	4,060	36
Coal fixed-for-float swaps sold	3,720	36
Coal physical purchases	24,634	48
Coal physical sales	9,046	36
Coal options purchased	2,835	48
Coal options sold	270	12

* Coal contracts represent the contractual positions of the coal marketing business which was acquired on June 1, 2010 and subsequent contracts arising from trading activity.

	2010	
	Notional Amounts	Latest Expiration (months)
Power (thousands of MWh): **		
Power fixed-for-float swap purchases	902	11
Power fixed-for-float swap sales	902	11

** Power contracts represent the contractual positions of the power marketing business which commenced in the third quarter of 2010.

Our derivatives and certain energy marketing activities are marked to fair value, and the associated 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 were as follows (in thousands):

	2010	2009
Current assets	$ 43,862	$ 25,366
Non-current assets	$ 6,635	$ 3,090
Current liabilities	$ 14,550	$ 9,377
Non-current liabilities	$ 3,464	$ (733)
Cash collateral receivables/(payables) included in derivative assets/liabilities[a]	$ 3,958	$ 2,728
Unrealized gain	$ 28,525	$ 17,084

(a) When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. Accounting standards also permit offsetting of 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.

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, 2010 and 2009, the market adjustments recorded in inventory were $(9.1) million and $(0.3) 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 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 accounting standards for derivatives and hedges and we generally elect to utilize hedge accounting as allowed under this standard.

We held a portfolio of swaps and options to hedge portions of our crude oil and natural gas production for which we elected hedge accounting on the over-the-counter swaps and options. These transactions were designated at inception as cash flow hedges, properly documented and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income (loss) and the ineffective portion was reported in earnings.

We had the following swaps, options and related balances as of December 31 (dollars in thousands):

	2010		2009	
	Crude oil swaps/options	Natural gas swaps	Crude oil swaps/options	Natural gas swaps
Notional*	424,500	6,821,800	472,500	9,602,300
Maximum duration in years**	0.25	0.25	0.25	0.75
Current assets	$ 248	$ 7,675	$ 3,345	$ 5,994
Non-current assets	$ 19	$ 2,606	$ 136	$ 551
Current liabilities	$ 3,814	$ —	$ 1,220	$ 1,435
Non-current liabilities	$ 1,301	$ —	$ 2,502	$ 391
Pre-tax accumulated other comprehensive income (loss)	$ (5,313)	$ 10,281	$ (862)	$ 4,719
Earnings	$ 465	$ —	$ 621	$ —

* 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.

The majority of our crude oil and natural gas hedges are deemed 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 (loss) will be realized in earnings during the next twelve months. Based on December 31, 2010 market prices, a $3.4 million gain would be realized and reported in earnings during 2011. Estimated and actual realized gains will likely change during 2011 as market prices fluctuate.

Gas Utilities

Our Gas Utilities purchase natural gas and distribute it in four states. During the winter heating season, our gas customers are exposed to potential price volatility; therefore, as allowed or required by state utility commissions, we have entered into certain exchange-traded natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives in accordance with accounting standards for derivatives and hedging and mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. Gains and losses, as well as option premiums, on these transactions are recorded as Regulatory assets or Regulatory liabilities in accordance with accounting standards for regulated operations. Accordingly, the earnings impact is recognized in the Consolidated Statements of Income as a component of PGA costs when the related costs are recovered through our rates as part of PGA costs in operating revenue.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Gas Utilities as of December 31 were as follows:

	2010		2009	
	Notional*	Latest Expiration (months)	Notional*	Latest Expiration (months)
Natural gas futures purchased	6,670,000	15	6,220,000	15
Natural gas options purchased	1,730,000	3	1,910,000	3
Natural gas basis swaps purchased	—	—	225,000	3

* Gas in MMBtu

Our Gas Utilities held the following derivative-related balances as of December 31 (in thousands):

	2010	2009
Current derivative assets[a]	$ 4,787	$ 3,042
Non-current derivative assets	$ —	$ —
Current derivative liabilities	$ —	$ —
Non-current derivative liabilities	$ 1,620	$ 764
Regulatory assets	$ 8,030	$ 2,578
Cash collateral included in derivative assets/liabilities[b]	$ 10,355	$ 3,789
Option premium [a]	$ 842	$ 1,067

(a) Current derivative assets include option premiums which will be recorded as a regulatory asset upon settlement of the options.

(b) A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of 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 agreement.

Electric Utilities

At our Electric Utilities, we occasionally hold natural gas in storage for use as fuel for generating electricity with our gas-fired combustion turbines. To minimize associated price risk and seasonal storage level requirements, we occasionally utilize various derivative instruments. These transactions are marked-to-market, designated as cash flow hedges, and recorded in Derivative liabilities, current and Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets. Gains or losses on these transactions will be recorded in gross margins upon settlement.

We had the following swaps and related balances as of December 31 (dollars, in thousands):

	2010	2009
Notional*	—	232,500
Maximum terms in months	—	10
Current derivative liability	$ —	$ 5
Pre-tax accumulated other comprehensive income (loss)	$ —	$ (5)

* Gas in MMBtu

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, 2010, we had $150.0 million of notional amount floating-to-fixed interest rate swaps designated as cash flow hedges in accordance with accounting guidance for derivatives and hedging and accordingly, the mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets.

- We also had $250.0 million notional amount interest rate swaps 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 accounting standards for derivatives and the mark-to-market values were recorded in Accumulated other comprehensive loss on the Consolidated Balance Sheets. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated.

  Mark-to-market adjustments on the swaps are now recorded within the income statement. During 2010 we recorded a $15.2 million pre-tax unrealized mark-to-market loss, in 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain, while in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market charge to earnings. These swaps are eight and 18 year swaps which have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011. We have continued to maintain these swaps in anticipation of our upcoming financing needs, particularly as they relate to our planned capital requirements to build gas-fired power generation facilities to serve our Colorado Electric customers and our upcoming holding company debt maturities, which are $225 million and $250 million in years 2013 and 2014, respectively. Alternatively, we may choose to cash settle these swaps at their fair value prior to their mandatory early termination dates, or unless these dates are extended, we will cash settle these swaps for an amount equal to their fair value on the stated termination dates.

Our interest rate swaps and related balances were as follows as of December 31 (dollars in thousands):

	2010		2009	
	Interest Rate Swaps	De-designated Interest Rate Swaps [a]	Interest Rate Swaps	De-designated Interest Rate Swaps [a]
Notional	$ 150,000	$ 250,000	$ 150,000	$ 250,000
Weighted average fixed interest rate	5.04 %	5.67 %	5.04 %	5.67 %
Maximum terms in years	6.0	1.0	7.0	1.0
Current derivative assets	$ —	$ —	$ —	$ —
Non-current derivative assets	$ —	$ —	$ —	$ —
Current derivative liabilities	$ 6,823	$ 53,980	$ 6,342	$ 38,787
Non-current derivative liabilities	$ 14,976	$ —	$ 9,075	$ —
Pre-tax accumulated other comprehensive (loss)	$ (21,799)	$ —	$ (15,417)	$ —
Pre-tax gain (loss)	$ —	$ (15,193)	$ —	$ 55,653

(a) The maximum term in years reflects the amended mandatory early termination dates of the eight and 18 year swaps in 2010 and nine and 19 year swaps in 2009. If the mandatory early termination dates are not extended, the swaps will require cash settlement based on the swap value on the termination date.

Based on December 31, 2010 market interest rates and balances, a loss of approximately $6.8 million would be realized and reported in pre-tax earnings during the next 12 months associated with our interest rate swaps that have been designated as hedges. Estimated and realized losses will change during the next 12 months as market interest rates fluctuate.

Foreign Exchange Contracts

Our Energy Marketing Segment conducts its gas marketing in the United States and Canada. Transactions in Canada are generally transacted in Canadian dollars and create exchange 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 dollar and United States dollar.

The outstanding forward exchange contracts have been recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets. We had the following outstanding forward contracts included in Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets as of December 31 as follows (in thousands):

	2010		2009	
	Notional Amounts	Latest Expiration (months)	Notional Amounts	Latest Expiration (months)
Canadian dollars purchased	$ 15,000	1	$ —	—

Our outstanding foreign exchange contracts had a fair value as of December 31 as follows (in thousands):

	2010	2009
Fair Value	$ (143)	$ —

Currency transaction gains or losses on transactions executed in Canadian dollars are recorded in Revenues, Non-regulated energy on the accompanying Consolidated Statements of Income as incurred. We recognized the following gains and losses in Revenues, Non-regulated energy on the accompanying Consolidated Statements of Income for the years ended (in thousands):

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	December 31, 2010	December 31, 2009	December 31, 2008
Unrealized foreign exchange gain (loss)	$ 458	$ 195	$ 289
Realized foreign exchange gain (loss)	$ (501)	$ 1,902	$ (1,433)

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 master 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.

As of December 31, 2010, our credit exposure (exclusive of retail customers of the regulated utilities) was concentrated primarily among investment grade companies. Approximately 75% 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.

(4) FAIR VALUE MEASUREMENTS

Accounting standards for fair value measurements require, among other things, enhanced disclosures regarding assets and liabilities carried at fair value and also provide 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 accounting standards for fair value measurements, 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.

Disclosures are required based on 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 their own judgments about the assumptions a market participant would use in pricing the asset or liability.

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 the placement within the fair value hierarchy levels. The following tables set 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 (in thousands):

	December 31, 2010				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral [a]	Total
Assets:					
Commodity derivatives - Energy Marketing	$ —	$ 166,405	$ 7,976	$ (124,049)	$ 50,332
Commodity derivatives - Oil and Gas	—	10,281	266	—	10,547
Commodity derivatives - Regulated Utilities	—	(5,568)	—	10,355	4,787
Money market fund	8,050	—	—	—	8,050
Foreign currency	—	166	—	—	166
Total	$ 8,050	$ 171,284	$ 8,242	$ (113,694)	$ 73,882
Liabilities:					
Commodity derivatives - Energy Marketing	$ —	$ 143,537	$ 2,463	$ (128,007)	$ 17,993
Commodity derivatives - Oil and Gas	—	5,115	—	—	5,115
Commodity derivatives - Regulated Utilities	—	1,620	—	—	1,620
Foreign currency	—	21	—	—	21
Interest rate swaps	—	75,779	—	—	75,779
Total	$ —	$ 226,072	$ 2,463	$ (128,007)	$ 100,528

	December 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting and Cash Collateral [a]	Total
Assets:					
Commodity derivatives	$ —	$ 154,205	$ 4,879	$ (117,560)	$ 41,524
Money market fund	6,000	—	—	—	6,000
Total	$ 6,000	$ 154,205	$ 4,879	$ (117,560)	$ 47,524
Liabilities:					
Commodity derivatives	$ —	$ 133,604	$ 5,435	$ (124,078)	$ 14,961
Interest rate swaps	—	54,204	—	—	54,204
Total	$ —	$ 187,808	$ 5,435	$ (124,078)	$ 69,165

(a) Cash collateral on deposit in margin accounts at December 31, 2010 and December 31, 2009 totaled a net $14.3 million and $6.5 million, respectively.

The following tables present the changes in level 3 recurring fair value (in thousands):

	Commodity Derivatives December 31, 2010
Balance at beginning of year	$ (556)
Unrealized losses	(2,827)
Unrealized gains	7,482
Purchases	—
Issuances	—
Settlements	(1,179)
Transfers in to level 3[a]	1,457
Transfers out of level 3 [b]	1,402
Balance at year end	$ 5,779
Changes in unrealized (losses) gain relating to instruments still held as of year end	$ 776

		Commodity Derivatives	
		December 31, 2009	December 31, 2008
Balance at beginning of year	$	16,398 $	6,422
Realized and unrealized (losses) gains		(10,709)	11,059
Purchases, issuance and (settlements)		(164)	(1,083)
Transfers in and/or (out) of level 3[(a) (b)]		(6,081)	—
Balance at year end	$	(556) $	16,398
Changes in unrealized (losses) gains relating to instruments still held as of year end	$	(1,836) $	1,886

(a) Transfers into level 3 represent existing assets and liabilities that were previously categorized as a higher level for which the inputs became unobservable.
(b) Transfers out of level 3 represent existing assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

Gains and losses (realized and unrealized) for level 3 commodity derivatives totaling $5.0 million for the year ended December 31, 2010, are included in Operating revenues on the Consolidated Statements of Income while ($0.3) million was recorded through AOCI on the Consolidated Balance Sheet for the year ended December 31, 2010. Commodity derivatives classified as level 3, 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 period.

Fair Value Measures

As required by accounting standards for derivatives and hedging, fair values within the following tables are presented on a gross basis and do not reflect the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements. Further, the amounts do not include net cash collateral of $14.3 million and $6.5 million on deposit in margin accounts at December 31, 2010 and 2009, respectively to collateralize certain financial instruments, which are included in Derivative assets - current. Therefore, the gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Consolidated Balance Sheets, nor will they agree to the fair value measurements presented in Note 3.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31 (in thousands):

		December 31, 2010	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 10,952	$ 1,452
Commodity derivatives	Derivative assets - non-current	48	71
Commodity derivatives	Derivative liabilities - current	—	45
Commodity derivatives	Derivative liabilities - non-current	—	—
Interest rate swaps	Derivative liabilities - current	—	6,823
Interest rate swaps	Derivative liabilities - non-current	—	14,976
Total derivatives designated as hedges		$ 11,000	$ 23,367
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 149,936	$ 113,364
Commodity derivatives	Derivative assets - non-current	12,382	3,099
Commodity derivatives	Derivative liabilities - current	20,588	42,865
Commodity derivatives	Derivative liabilities - non-current	978	7,363
Foreign currency	Derivative assets - current	166	21
Interest rate swaps	Derivative liabilities - current	—	53,980
Total derivatives not designated as hedges		$ 184,050	$ 220,692

	Balance Sheet Location	December 31, 2009 Fair Value of Asset Derivatives	December 31, 2009 Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 4,163	$ 2,977
Commodity derivatives	Derivative assets - non-current	72	—
Commodity derivatives	Derivative liabilities - current	16	801
Commodity derivatives	Derivative liabilities - non-current	—	55
Interest rate swaps	Derivative liabilities - current	—	6,342
Interest rate swaps	Derivative liabilities - non-current	—	9,075
Total derivatives designated as hedges		$ 4,251	$ 19,250
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets - current	$ 135,807	$ 103,035
Commodity derivatives	Derivative assets - non-current	6,490	2,785
Commodity derivatives	Derivative liabilities - current	19,089	33,069
Commodity derivatives	Derivative liabilities - non-current	946	3,815
Interest rate swaps	Derivative liabilities - current	—	38,787
Total derivatives not designated as hedges		$ 162,332	$ 181,491

A description of our derivative activities is discussed in Note 3. The following tables present the impact that derivatives had on our Consolidated Statements of Income.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged items on our accompanying Consolidated Statements of Income is presented as follows (in thousands):

Derivatives in Fair Value Hedging Relationships	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income December 31, 2010	Amount of Gain/(Loss) on Derivatives Recognized in Income December 31, 2009
Commodity derivatives	Revenues	$ 9,015	$ 8,148
Fair value adjustment for natural gas inventory designated as the hedged item	Revenues	(8,772)	(9,064)
Total		$ 243	$ (916)

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income and Balance Sheets for the years ended are presented as follows (in thousands):

	December 31, 2010				
Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/ (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$ (13,527)	Interest expense	$ (7,609)		$ —
Commodity derivatives	15,456	Revenues	14,339	Revenues	—
Total	$ 1,929		$ 6,730		$ —

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/ (Loss) Reclassified from AOCI into Income (Effective Portion)	December 31, 2009 Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	$ 12,818	Interest expense	$ (3,292)		$ —
Commodity derivatives	(21,070)	Revenues	23,102	Revenues	(1,394)
Total	$ (8,252)		$ 19,810		$ (1,394)

Derivatives Not Designated as Hedge Instruments

The impact of derivative instruments that have not been designated as hedging instruments on our Consolidated Statements of Income for the years ended December 31 was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Revenues	$ (151)
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swap	(15,193)
Interest rate swaps - realized	Interest expense	(13,312)
Foreign currency contracts	Revenues	142
		$ (28,514)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Revenue	$ (27,280)
Interest rate swap	Unrealized gain (loss) on interest rate swap	55,653
Interest rate swaps - realized	Interest expense	(9,816)
Foreign currency contracts	Revenue	227
		$ 18,784

(5) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 32,438	$ 32,438	$ 112,901	$ 112,901
Restricted cash	$ 4,260	$ 4,260	$ 17,502	$ 17,502
Derivative financial instruments - assets	$ 65,832	$ 65,832	$ 41,524	$ 41,524
Derivative financial instruments - liabilities	$ 100,528	$ 100,528	$ 69,165	$ 69,165
Notes payable	$ 249,000	$ 249,000	$ 164,500	$ 164,500
Long-term debt, including current maturities	$ 1,191,231	$ 1,290,519	$ 1,051,157	$ 1,123,703

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

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash accounts as of December 31, 2010 represent amounts required by Black Hills Wyoming project financing agreements. Of this total, $3.6 million is held in 30-day Guaranteed Investment Certificates.

Derivative Financial Instruments

These instruments are carried at fair value. The Company's fair value measurements are developed using a variety of inputs by its risk management group, which is independent of the trading function. These inputs include unadjusted quoted prices where available; prices published by various third-party providers; and, when necessary, internally developed adjustments. In many cases, the internally developed prices are corroborated with external sources. Certain Company transactions take place in markets with limited liquidity and limited price visibility. Descriptions of the various instruments we use and the valuation methods employed are included in Notes 3 and 4.

Notes Payable

The carrying amount of our notes payable 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.

(6) PROPERTY, PLANT AND EQUIPMENT

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

Utilities Group	2010		2009		
Electric Utilities		Weighted Average Useful Life		Weighted Average Useful Life	Lives (in years)
Electric plant:					
Production	$ 679,165	47	$ 537,263	48	20-65
Transmission	154,936	47	101,223	47	35-65
Distribution	543,498	43	541,611	43	15-65
Plant acquisition adjustment	4,870	32	4,870	32	32
General	103,455	20	98,610	20	3-50
Total electric plant	1,485,924		1,283,577		
Less accumulated depreciation and amortization	357,774		337,600		
Electric plant net of accumulated depreciation and amortization	1,128,150		945,977		
Construction work in progress	234,985		277,274		
Electric plant, net	$ 1,363,135		$ 1,223,251		
Gas Utilities					
Gas plant:					
Production	$ 35	37	$ 35	37	37
Transmission	15,704	48	13,923	48	30-57
Distribution	406,914	45	380,149	45	36-56
General	68,315	19	63,930	19	14-22
Total gas plant	490,968		458,037		
Less accumulated depreciation and amortization	47,292		33,700		
Gas plant net of accumulated depreciation and amortization	443,676		424,337		
Construction work in progress	11,392		5,228		
Gas plant, net	$ 455,068		$ 429,565		

Non-regulated Energy	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
	2010						
Coal Mining	$ 135,157	$ 65,465	$ 69,692	$ 10,228	$ 79,920	11	3-40
Oil and Gas	680,407	357,979	322,428	—	322,428	26	3-27
Energy Marketing	7,931	3,699	4,232	163	4,395	4	2-20
Power Generation	134,616	30,982	103,634	163,291	266,925	36	2-40
	$ 958,111	$ 458,125	$ 499,986	$ 173,682	$ 673,668		

Non-regulated Energy	Property, Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Weighted Average Useful Life	Lives (in years)
	2009						
Coal Mining	$ 115,400	$ 56,646	$ 58,754	$ 3,962	$ 62,716	11	2-39
Oil and Gas	668,383	352,509	315,874	—	315,874	25	3-26
Energy Marketing	2,545	2,302	243	50	293	4	3-10
Power Generation	131,717	26,262	105,455	16,947	122,402	36	3-40
	$ 918,045	$ 437,719	$ 480,326	$ 20,959	$ 501,285		

	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)
	2010						
Corporate	$ 2,198	$ 1,138	$ 1,060	$ 2,502	$ 3,562	6	2-30

	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)
	2009						
Corporate	$ 8,736	$ 6,244	$ 2,492	$ 4,137	$ 6,629	6	2-10

(7) JOINTLY OWNED FACILITIES

Oil and Gas

- 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 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, 2010, our investment in the Gas Plant included $4.2 million in plant and equipment which is included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. This asset is included in the asset pool being depleted and therefore accumulated depreciation is not separated by asset. These items are included in the corresponding categories of operating revenues and expenses in the accompanying Consolidated Statements of Income.

Our share of the Gas Plant for the year ended December 31 was as follows (in thousands):

	2010	2009	2008
Revenues	$ 3,088	$ 2,259	$ 4,131
Direct expenses	$ 503	$ 442	$ 440

Utility Plant

- Our subsidiary, Black Hills Power, owns a 20% interest in the Wyodak Plant, a 362 MW coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining 80% and operates the Wyodak 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. Black Hills Power's share of direct expenses of the Wyodak Plant is included in the corresponding categories of Operating expenses in the accompanying Consolidated Statements of Income. In addition to supplying Black Hills Power with coal for its share of the Wyodak Plant, our Coal Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak 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.

  Our share of the Wyodak Plant direct expenses and the total amount of coal sales from WRDC to the Wyodak Plant for the year ended December 31 was as follows (in thousands):

	2010	2009	2008
Direct expenses	$ 8,546	$ 8,021	$ 8,000
WRDC coal sales to Wyodak Plant	$ 21,958	$ 22,814	$ 23,276

- Black Hills Power also owns a 35% interest in, and is the operator of, 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 year ended December 31, 2010, 2009 and 2008, Black Hills Power's share of direct expenses was $0.2 million, $0.1 million and $0.1 million, respectively.

- On April 1, 2010, the 110 MW Wygen III coal-fired generation facility began commercial operations. Black Hills Power owns 52% of this facility.

  On April 9, 2009, Black Hills Power sold to MDU a 25% undivided ownership interest in the 110 MW Wygen III generation facility which was under construction at that time. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility and subsequently reimbursed Black Hills Power for 25% of the total costs paid to complete the project.

  On July 14, 2010, Black Hills Power sold a 23% ownership interest in Wygen III to the City of Gillette. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include the City of Gillette. We retain responsibility for plant operations following the transaction. The Participation Agreement provides that the City of Gillette will pay Black Hills Power for administrative services and share in the costs of operating the plant for the life of the facility.

  Our share of Wygen III plant expenses, included in the corresponding categories of Operating expenses in the accompanying Consolidated Statements of Income, for the year ended December 31 was as follows (in thousands):

	2010
Direct expenses	$ 7,618

- In January 2009, Black Hills Wyoming sold a 23.5% undivided ownership interest in its 90 MW Wygen I Plant to MEAN and in conjunction with the sale, we entered into agreements with MEAN under which it is obligated to 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 retain responsibility for plant operations following the transaction.

Black Hills Wyoming's share of direct expenses of the Wygen I Plant are included in Operating expenses in the accompanying Consolidated Statements of Income.

Our share of the Wygen I plant expenses for the years ended December 31, was as follows (in thousands):

	2010	2009
Direct expenses	$ 14,406	$ 11,000

At December 31, 2010, our interests in jointly-owned generating facilities and transmission systems were (dollars in thousands):

	Ownership %	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	20.0%	$ 82,466	$ 21,687	$ 54,108
Transmission Tie	35.0%	19,644	—	4,111
Wygen I	76.5%	104,166	620	20,147
Wygen III	52.0%	129,340	194	2,282
		$ 335,616	$ 22,501	$ 80,648

(8) LONG-TERM DEBT

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

	2010	2009
Senior unsecured notes:		
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes due 2013	(70)	(99)
Senior unsecured notes at 9.0% due 2014	250,000	250,000
Senior unsecured notes at 5.875% due in 2020	200,000	—
Total senior unsecured notes	674,930	474,901
First mortgage bonds:		
Electric Utilities		
Black Hills Power:		
8.06% due 2010	—	30,000
9.49% due 2018	—	2,520
9.35% due 2021	—	19,980
7.23% due 2032	75,000	75,000
6.125% due 2039	180,000	180,000
Unamortized discount on 6.125% bonds	(119)	(124)
Cheyenne Light:		
6.67% due 2037	110,000	110,000
Industrial development revenue bonds due 2021, variable rate, at 0.4% [(a)]	7,000	7,000
Industrial development revenue bonds due 2027, variable rate, at 0.4% [(a)]	10,000	10,000
Total first mortgage bonds	381,881	434,376
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 long-term debt	3,089	3,230
Total other long-term debt	21,739	21,880
Project financing floating rate debt:		
Black Hills Wyoming project financing due 2016, variable rate debt at 3.54% [(a)]	112,681	120,000
Total long-term debt	1,191,231	1,051,157
Less current maturities	(5,181)	(35,245)
Net long-term debt	$ 1,186,050	$ 1,015,912

(a) Interest rates are presented as of December 31, 2010.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for the next five years and thereafter are (in thousands):

2011	$	5,181
2012		2,473
2013		228,973
2014		262,473
2015		6,964
Thereafter		685,356
Total	$	1,191,420

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, 2010.

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. 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 benefit for us to call the bonds.

Black Hills Power Series AC Bonds

In February 2010, the Black Hills Power Series 8.06% AC bonds matured. These were paid in full for $30.0 million of principal plus accrued interest of $1.2 million.

Black Hills Power Series Y Bonds

In March 2010, Black Hills Power completed redemption of its Series Y 9.49% bonds in full. The bonds were originally due in 2018. A total of $2.7 million was paid on March 31, 2010, which includes the principal balance of $2.5 million plus accrued interest and an early redemption premium of 2.618%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheet and is being amortized over the remaining term of the original bonds.

Black Hills Power Series Z Bonds

In June 2010, Black Hills Power completed redemption of its Series Z 9.35% bonds in full. The bonds were originally due in 2021. A total of $21.8 million was paid on June 1, 2010, which included the principal balance of $20.0 million plus accrued interest and an early redemption premium of 4.675%. The early redemption premium was recorded in unamortized loss on reacquired debt which is included in Regulatory assets on the accompanying Consolidated Balance Sheet and is being amortized over the remaining term of the original bonds.

$200 Million Debt Offering

In July 2010, pursuant to a public offering, we issued $200.0 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Deferred financing costs of $1.7 million are being amortized over the 10-year term of the debt. Amortization of deferred financing costs is included in interest expense.

$250 Million Debt Offering

In May 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds, net of underwriting fees, of $248.5 million. Proceeds were used to pay down the Acquisition Facility. Deferred financing costs capitalized are being amortized over the term of the debt. Amortization of deferred financing costs is included in interest expense.

Industrial Development Revenue Bonds

In September 2009, Cheyenne Light completed a $17 million weekly variable rate refunding bond issuance. The new issue replaced existing debt and converted the bond credit support structure from an AMBAC Financial Group insurance policy to a direct-pay letter of credit issued by Wells Fargo Bank. Laramie County, Wyoming was the tax-exempt conduit issuer for this transaction. The bonds were issued in two series: a $10.0 million series maturing March 1, 2027 and a $7.0 million series maturing September 1, 2021. The principal amounts and maturity dates did not change from the original financing. Including the letter of credit fees and other issuance costs, the all-in rate as of December 31, 2010 was approximately 2.77%.

Under the terms of our Reimbursement Agreement with the letter of credit provider, Cheyenne Light is required to maintain a debt to capitalization ratio of no more than 0.60 to 1.00 and a interest coverage ratio greater than or equal to 2.50 to 1.00. If Cheyenne Light fails to meet these covenants, subject to a 30-day cure period, it would constitute an event of default and the bank would have the right to cause the bonds and related outstanding obligations to become immediately due and payable.

Black Hills Power Bond Issuance

In October 2009, Black Hills Power completed a $180 million first mortgage bond issuance. The bonds were priced at 99.931% of par with a re-offer yield of 6.13%. The bonds mature on November 1, 2039 and carry an annual interest rate of 6.125%, which is paid semi-annually. We received proceeds net of underwriting fees of $178.3 million which were used to repay intercompany borrowings under the Utility Money Pool agreement, primarily incurred to fund the construction of Wygen III and repayment of bonds. Deferred financing costs of approximately $2.2 million were capitalized and are being amortized over the term of the bonds.

Black Hills Wyoming

On December 9, 2009, Black Hills Wyoming issued $120 million in project financing debt. Proceeds were used to pay down short-term borrowings on our Corporate Credit Facility. The loan amortizes over a seven year term and matures on December 9, 2016, at which time the remaining unamortized balance of $78.8 million is due. Principal and interest payments are made on a quarterly basis with the principal payments based on projected cash flows available for debt service. Additional quarterly principal payments are required based upon actual cash flows available for debt service. Interest is charged at LIBOR plus 3.25%. Deferred financing costs capitalized are being amortized over the term of the debt. Amortization of deferred financing costs is included in interest expense.

Our Black Hills Wyoming project financing is secured by our ownership interest in the Wygen I plant and by the Gillette CT generation facility. The financing places restrictions on dividends or the loaning of funds by Black Hills Wyoming, and allows dividends or loans only in limited circumstances when cash flows for the projects exceed project debt service and reserve requirements.

Under the terms of the Black Hills Wyoming project financing, Black Hills Wyoming was required to become a party to hedging agreements fixing the interest rate on $75 million of the principal amount of the debt. To accomplish this, two existing swap agreements with notional amounts totaling $75 million were amended so that BHC and Black Hills Wyoming are now both jointly and severally liable for the full amount of the obligations under the swap agreements. As of January 15, 2010, the mark to market liability associated with the two swaps was transferred from BHC to Black Hills Wyoming. The balance in AOCI as of January 15, 2010 on BHC was frozen at that point in time and is being amortized over the remaining life of the swaps through the quarterly settlement process.

Amortization Expense

Our deferred financing costs and associated amortization expense were as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet at December 31, 2010	Amortization Expense for the years ended December 31, 2010	2009	2008
Senior unsecured notes at 6.5% due 2013	$ 528	$ 218	$ 218	$ 218
Senior unsecured notes at 9% due 2014	$ 1,559	$ 462	$ 289	$ —
Senior unsecured notes at 5.875% due in 2020	$ 1,595	$ 77	$ —	$ —
Black Hills Power first mortgage bonds at 7.23% due 2032	$ 717	$ 33	$ 33	$ 33
Black Hills Power first mortgage bonds at 6.125% due 2039	$ 2,189	$ 76	$ 12	$ —
Cheyenne Light 6.67% due 2037	$ 828	$ 31	$ 31	$ 31
Black Hills Wyoming project financing due 2016	$ 5,226	$ 1,036	$ 60	$ —
Other	$ 886	$ 74	$ 67	$ 149

(9) NOTES PAYABLE

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, 2010, we were in compliance with all of these financial covenants. None of our facilities or debt securities contain default provisions pertaining to our credit ratings.

Revolving Credit Facility

On April 15, 2010, we terminated our $525 million Corporate Credit Facility and entered into a new $500 million Revolving Credit Facility expiring April 14, 2013. The new facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase the capacity of the new facility to $600 million and can be used for the issuance of letters of credit, to fund working capital needs and other corporate purposes. The covenants and events of default are substantially the same as the prior facility, except the minimum interest expense coverage ratio covenant was eliminated. Borrowings are available under a base rate option or a Eurodollar option. The cost of borrowings or letters of credit is determined based upon our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at December 31, 2010. The new facility contains a commitment fee to be charged on the unused amount of the Revolving Credit Facility. Based upon current credit ratings, the fee is 0.5%.

We had $149.0 million of borrowings and $46.9 million of letters of credit and $164.5 million of borrowings and $44.8 million of letters of credit issued under the Revolving Credit Facility and Corporate Credit Facility at December 31, 2010 and 2009, respectively. Deferred financing costs are being amortized over the three-year term of the Revolving Credit Facility and are included in Interest expense on the accompanying Consolidated Statements of Income as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of December 31, 2010	Amortization Expense for the years ended December 31, 2010	2009	2008
Amortization expense [(a)]	$ 3,389	$ 1,340	$ 495	$ 489

(a) Amortization expense for 2010 relates to our new Revolving Credit Facility, while 2009 and 2008 relates to the Corporate Credit Facility which was terminated in April 2010.

The Revolving Credit Facility includes the following covenants that we must comply with at the end of each quarter (dollars, in thousands). We were in compliance with these covenants as of December 31, 2010.

	Actual	Covenant Requirement
Consolidated net worth	$ 1,100,270	$ 859,266
Recourse leverage ratio	57.5 %	65.0 %

Corporate Term Loan

In December 2010, we entered into a one-year $100.0 million term loan (the "Loan) with J.P. Morgan and Union Bank due in December 2011. The cost of borrowings under the Loan was based on a spread of 137.5 basis points over LIBOR (1.69%% at December 31, 2010). The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as the Revolving Credit Facility.

Enserco Credit Facility

In May 2010, Enserco entered into an agreement for a two-year $250.0 million committed credit facility. The facility contains an accordion feature which allows us, with the consent of the administrative agent, to increase commitments under the facility to $350 million. This facility replaced the $300 million credit facility which expired on May 7, 2010. Borrowings under the Enserco Credit Facility are subject to a sub-limit of $50 million. Borrowings under this facility are available under a base rate option or a Eurodollar option. Margins for base rate borrowings are 1.75% and for Eurodollar borrowings are 2.50%.

At December 31, 2010, $166.9 million of letters of credit were issued and outstanding under this facility and there were no cash borrowings outstanding.

Deferred financing costs capitalized are being amortized over the term of the Enserco Credit Facility. Amortization of deferred financing costs included in Interest expense on the accompanying Consolidated Statements of Income was as follows (in thousands):

	Deferred Financing Costs Remaining on Balance Sheet as of December 31, 2010	Amortization Expense for the years ended December 31, 2010	2009	2008
Amortization expense	$ 1,520	$ 1,514	$ 1,394	$ 559

The June 1, 2010 coal marketing acquisition (see Note 23) included certain contractual positions that caused Enserco to temporarily not be in compliance with one of the non-financial covenants to the Enserco Credit Facility as of June 30, 2010. The Enserco Credit Facility limited the net fixed price volume of coal. As of June 30, 2010, Enserco was above that limit. In July, the participating banks waived the non-compliance with this covenant and increased the permitted net fixed price volume of coal allowed. Enserco was in compliance with covenants as of December 31, 2010.

In September 2010, the Enserco Credit Facility was amended to allow for trading of electric power, renewable energy credits and emissions credits.

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. During 2009, we repaid the Acquisition Facility with proceeds of $30.2 million from the sale of 25% of the Wygen III plant to MDU, net proceeds from the $250 million public debt offering, and with a borrowing of $104.6 million on our Corporate Credit Facility.

(10) ASSET RETIREMENT OBLIGATIONS

Accounting standards for asset retirement obligations associated with long-lived assets require 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 accounting standards for regulated operations. 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 regulated Electric Utilities segment and asbestos at our regulated Gas Utilities segment.

The following tables present the details of ARO which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	12/31/09	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	12/31/10
Oil and Gas	$ 21,233	$ 570	$ (2,078)	$ 1,280	$ 658	$ 21,663
Coal Mining	15,285	18,094	(15,207)	1,246	(1,858)	17,560
Electric Utilities	2,904	—	—	135	—	3,039
Gas Utilities	241	—	—	14	—	255
Total	$ 39,663	$ 18,664	$ (17,285)	$ 2,675	$ (1,200)	$ 42,517

	12/31/08	Liabilities Incurred	Liabilities Settled	Accretion	Revisions to Prior Estimates	12/31/09
Oil and Gas	$ 19,623	$ 192	$ (239)	$ 1,226	$ 431	$ 21,233
Coal Mining	17,699	7,909	(5,414)	1,118	(6,027)	15,285
Electric Utilities	2,616	—	—	288	—	2,904
Gas Utilities	222	—	—	19	—	241
Total	$ 40,160	$ 8,101	$ (5,653)	$ 2,651	$ (5,596)	$ 39,663

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.

(11) COMMON STOCK

Equity Compensation Plans

Our 2005 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 1,125,958 shares available to grant at December 31, 2010.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2010, total unrecognized compensation expense related to non-vested stock awards was $7.0 million and is expected to be recognized over a weighted-average period of 1.8 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income was as follow (in thousands):

	2010	2009	2008
Stock-based compensation expense	$ 5,848	$ 3,983	$ 1,345

Stock Options

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 options at December 31, 2010 was as follows:

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		(in years)	(in thousands)
Balance at January 1, 2010	336	$ 32.28		
Granted	—	—		
Forfeited/cancelled	—	—		
Expired	(58)	35.81		
Exercised	(43)	24.05		
Balance and exercisable at December 31, 2010	235	$ 32.92	2.24	$ (289)

The table below provides details of our option plans (in thousands):

	2010	2009	2008
Summary of Stock Options			
Option granted	—	—	—
Unrecognized compensation expense	$ —	$ —	$ —
Intrinsic value of options exercised [a]	$ 234	$ 255	$ 1,195
Net cash received from exercise of options	$ 1,034	$ 1,740	$ 2,267
Tax benefit realized from exercise of shares [b]	$ 82	$ 89	$ 418

(a) The intrinsic value represents the amount by which the market price of the stock on the date of exercise exceeded the exercise price of the option.
(b) The tax benefit realized from the exercise of shares granted was recorded as an increase in equity.

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, 2010 was as follows:

	Restricted Stock and Stock Units	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at January 1, 2010	186	$ 29.92
Granted	181	27.30
Vested	(78)	31.92
Forfeited	(19)	27.22
Balance at December 31, 2010	270	$ 27.78

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 was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in thousands)
2010	$ 27.30	$ 2,212
2009	$ 26.76	$ 1,799
2008	$ 32.39	$ 2,061

As of December 31, 2010, there was $4.8 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 1.9 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 and can range from 0% to 175% of target. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

Outstanding Performance Periods at December 31 were as follows (shares in thousands):

Grant Date	Performance Period	Target Grant of Shares
January 1, 2008	January 1, 2008 - December 31, 2010	26
January 1, 2009	January 1, 2009 - December 31, 2011	75
January 1, 2010	January 1, 2010 - December 31, 2012	75

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 determined that a change-in-control is probable, the equity portion of $1.6 million at December 31, 2010 would be reclassified as a liability.

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average December 31, 2010 Fair Value
	(in thousands)		(in thousands)	
Balance at January 1, 2010	66	$ 33.67	66	
Granted	38	24.26	38	
Forfeited	(3)	32.20	(3)	
Vested	(14)	34.16	(14)	
Balance at December 31, 2010	87	$ 29.47	87	$ 27.41

The grant date fair values for the performance shares granted in 2010, 2009 and 2008 were determined by Monte Carlo simulation using a blended volatility of 31%, 39% and 23%, 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, 2010, 2009 and 2008 was as follows:

	Weighted Average Grant Date Fair Value
2010	$ 24.26
2009	$ 29.20
2008	$ 46.00

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Stock Issued	Cash Paid	Total Intrinsic Value
January 1, 2007 to December 31, 2009	2010	—	$ —	$ —
January 1, 2006 to December 31, 2008	2009	—	$ —	$ —
January 1, 2005 to December 31, 2007	2008	35	$ 1,526	$ 3,051

On January 26, 2011, the Compensation Committee of our Board of Directors determined that the plan criteria for the January 1, 2008 to December 31, 2010 performance period was not met. As a result, there will be no payout for this performance period.

As of December 31, 2010, there was $2.2 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.

Dividend Reinvestment and Stock Purchase Plan

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. In March 2009, we began issuing new shares.

A summary of the Dividend Reinvestment and Stock Purchase Plan was as follows (shares in thousands):

	2010	2009
Shares Issued	106	143
Weighted Average Price	$ 29.57	$ 21.63
Unissued Shares Available at December 31	190	196

Other Plans

We issued 9,625 fully-vested shares of common stock with an intrinsic value of $0.3 million in the year ended December 31, 2010 to certain key employees under the Short-term Annual Incentive Plan, a performance-based plan. The payout was fully accrued at December 31, 2009. We issued 47,331 and 32,568 shares of common stock in 2009 and 2008, respectively, under the Short-term Annual Incentive Plan.

In addition, we will issue common stock with an intrinsic value of approximately $0.2 million in 2011 for the 2010 Short-term Annual Incentive Plan.

Forward Equity Issuance

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of $28.70875 per share.

On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares. In conjunction with the underwriters' exercise of the 413,519 share over-allotment option, an additional Equity Forward Agreement was entered into with J.P. Morgan for the over-allotment shares, having the same terms as the original Forward Agreement (together with the Forward Agreement, the "Forward Agreements").

The forward price used to determine cash proceeds due Black Hills Corporation at settlement of the equity forward instruments underlying the Forward Agreement will be calculated based on the November 2010 public offering price of our common stock of $29.75 per share, adjusted for underwriting fees, and interest rate adjustments as specified in the Forward Agreements and expected dividends on our common stock during the period the instrument is outstanding. We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settle for any date up to maturity, for all or a portion of the equity forward shares.

The equity forward instrument held by J.P. Morgan, underlying the Forward Agreements, was accounted for as equity in accordance with accounting for Derivatives and Hedging - Contracts in Entity's Own Equity, and recorded at fair value at the execution of the Forward Agreements, and will not be subsequently adjusted for changes in fair value until settlement. Since the initial pricing of the equity forward instrument of $28.70875 per share was determined based on the November 2010 offering price of our common stock of $29.75 per share, less under writing fees of $1.04 per share, no premium on the transaction was due J.P. Morgan related to the Forward Agreements at execution, and no fair value was recorded to equity for the instrument. Proceeds or payments due at settlement of all or portions of the equity forward instrument will be recorded with appropriate adjustments to additional paid in capital and common stock, depending on the method of settlement.

Based on the closing Black Hills Corporation common stock price of $30.00 on December 31, 2010, and the forward price on that date for the equity forward and over-allotment shares of $28.34, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $7.3 million. The Forward Agreements require a 60 day notice prior to settlement for cash or net share settlements. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

At December 31, 2010, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $125.1 million. Assuming required notices were given and actions taken, the forward instruments could have also been net settled at December 31, 2010 with delivery of cash of approximately $8.8 million or approximately 291,000 shares of common stock to J.P. Morgan.

Dividend Restrictions

Our credit facilities and other debt obligations 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 of our Revolving Credit Facility include the following: a recourse leverage ratio not to exceed 0.65 to 1.00 and a minimum consolidated net worth of $625 million plus 50% of aggregate consolidated net income since January 1, 2005. As of December 31, 2010, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2010:

- 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. Covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. In addition to the restrictions described above, each state in which we conduct utility operations imposes restrictions on affiliate transactions, including inter-company loans. Additionally, our utility subsidiaries are generally limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may be subject to further restrictions under the Federal Power Act. As of December 31, 2010, the restricted net assets at our regulated Electric and regulated Gas Utilities were approximately $196.8 million.

- Our Enserco credit facility is a borrowing base credit facility, the structure of which requires certain levels of tangible net worth and net working capital to be maintained for a given borrowing base election level. In order to maintain a borrowing base election level, Enserco may be restricted from making dividend payments to its parent company. Restricted net assets at Enserco totaled $93.0 million for this stand-alone Enserco Credit Facility at December 31, 2010.

- Pursuant to a covenant in the Black Hills Wyoming project financing, Black Hills Non-regulated Holdings has restricted assets of $100.0 million. In addition, Black Hills Wyoming holds $4.25 million of restricted cash in accordance with project financing requirements. Black Hills Non-regulated Holdings is the parent of Black Hills Electric Generation which is the parent of Black Hills Wyoming.

(12) IMPAIRMENT OF LONG LIVED ASSETS

<u>Oil and Gas Segment</u>

As a result of lower natural gas prices at March 31, 2009, we recorded a $43.3 million pre-tax non-cash ceiling test impairment of oil and gas assets included in the Oil and Gas segment. The write-down in the net carrying value of our natural gas and crude oil properties was recorded in Impairment of long-lived assets on the accompanying Consolidated Statements of Income and was based on the March 31, 2009 NYMEX price of $3.63 per Mcf, adjusted to $2.23 per Mcf at the wellhead, for natural gas; and NYMEX price of $49.66 per barrel, adjusted to $45.32 per barrel at the wellhead, for crude oil.

Also, as a result of low crude oil and natural gas prices at the end of 2008, we recorded a $91.8 million pre-tax non-cash ceiling test impairment charge of oil and gas assets included in the Oil and Gas segment. The write-down in the net carrying value of our natural gas and crude oil property was recorded in Impairment of long-lived assets on the accompanying Consolidated Statements of Income 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.

(13) OPERATING LEASES

We have entered into lease agreements for vehicle and office facilities. Rental expense incurred under these operating leases for the years ended December 31 was as follows (in thousands):

	2010	2009	2008
Rent expense	$ 4,962	$ 4,512	$ 3,453

The following is a schedule of future minimum payments required under the operating lease agreements for the next five years and thereafter (in thousands):

2011	$ 2,610
2012	2,003
2013	1,488
2014	1,369
2015	1,239
Thereafter	4,769
	$ 13,478

(14) INCOME TAXES

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2010	2009	2008
Current:			
Federal	$ 1,396	$ (6,124)	$ (215,957)
State	4,442	(222)	(1,330)
Foreign[1]	254	(82)	1,179
	6,092	(6,428)	(216,108)
Deferred:			
Federal	22,250	40,219	185,614
State	(2,707)	(108)	1,414
Tax credit amortization	(337)	(368)	(315)
	19,206	39,743	186,713
Total income tax expense (benefit)	$ 25,298	$ 33,315	$ (29,395)

(1) Foreign taxes represent income taxes incurred through our Canadian activities.

2008 amounts reflect income tax impacts associated with our like-kind exchange tax planning structure. The 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. In the third quarter of 2010, we reached an agreement with the Appeals Division of the IRS that resulted in a decrease of the amount of such deferral from $185 million to $125 million. The decrease represents the downward adjustment to tax depreciation allowed on certain assets sold, which resulted in a decrease to the gain realized on the sale of those assets and ultimately a decrease in deferred taxes. The remaining $125 million in deferred taxes relating to the IPP Transaction and the Aquila Transaction continues to be subject to IRS review.

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

		2010		2009
Deferred tax assets, current:				
Asset valuation reserves	$	1,797	$	1,651
Mining development and oil exploration		594		779
Unbilled revenue		—		581
Employee benefits		4,375		4,993
Items of other comprehensive loss		3,076		3,872
Derivative fair value adjustments		19,304		12,596
Deferred costs		342		—
Other deferred tax assets, current		5,607		2,940
Total deferred tax assets, current		35,095		27,412
Deferred tax liabilities, current:				
Asset valuation reserves		(312)		—
Prepaid expenses		(2,454)		(2,121)
Derivative fair value adjustments		(4,680)		(3,740)
Items of other comprehensive loss		(2,754)		(3,273)
Deferred costs		(4,621)		(5,132)
Other deferred tax liabilities, current		(3,161)		(8,623)
Total deferred tax liabilities, current		(17,982)		(22,889)
Net deferred tax asset, current	$	17,113	$	4,523
Deferred tax assets, non-current:				
Employee benefits	$	11,543	$	17,191
Regulatory liabilities		23,910		22,844
Deferred revenue		273		526
Deferred costs		—		471
State net operating loss		9,777		2,813
Items of other comprehensive income		22,306		10,535
Foreign tax credit carryover		3,352		2,966
Net operating loss (net of valuation allowance)		63,521		8,023
Asset impairment		47,033		47,557
Derivative fair value adjustments		3,038		902
Other deferred tax assets, non-current		11,076		16,413
Total deferred tax assets, non-current		195,829		130,241
Deferred tax liabilities, non-current:				
Accelerated depreciation, amortization and other plant-related differences		(314,728)		(237,578)
Regulatory assets		(16,050)		(34,097)
Mining development and oil exploration		(99,709)		(101,407)
Deferred costs		(17,534)		(9,491)
Derivative fair value adjustments		—		(1,254)
Items of other comprehensive income		(4,402)		(2,657)
State deferred tax liability		(11,613)		(5,791)
Other deferred tax liabilities, non-current		(8,929)		—
Total deferred tax liabilities, non-current		(472,965)		(392,275)
Net deferred tax liability, non-current	$	(277,136)	$	(262,034)
Net deferred tax liability	$	(260,023)	$	(257,511)

FORM 10K

The following table reconciles the change in the net deferred income tax liability from December 31, 2009 to December 31, 2010 to deferred income tax expense (in thousands):

	2010	2009
Net change in net deferred income tax assets (liabilities) from the preceding table	$ 2,512	$ 44,148
Deferred taxes associated with other comprehensive loss (income)	1,915	(941)
Deferred taxes related to net operating loss from acquisition	(312)	—
Deferred taxes related to regulatory assets and liabilities	25,370	(3,565)
Deferred taxes related to acquisition	(784)	7,992
Deferred taxes associated with property basis differences	(10,121)	(9,013)
Other net deferred income tax liability	626	1,122
Deferred income tax expense for the period	$ 19,206	$ 39,743

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

	2010	2009	2008
Federal statutory rate	35.0 %	35.0 %	(35.0)%
State income tax (net of federal tax effect)	1.1	(0.2)	—
Amortization of excess deferred and investment tax credits	(0.4)	(0.3)	(0.4)
Percentage depletion in excess of cost	(1.5)	(0.8)	—
Equity AFUDC	(1.0)	(1.7)	(1.4)
Tax credits	(2.9)	—	—
Accounting for uncertain tax positions adjustment	1.1	(2.1)	—
Flow-through adjustments *	(4.2)	—	—
Other tax differences	(0.3)	(0.2)	0.8
	26.9 %	29.7 %	(36.0)%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that was filed with the 2008 tax return and for which consent was received from the IRS in September 2009. The effect of the change allows us to take a current tax deduction for repair costs that were previously capitalized for tax purposes. These costs will continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. Due to this regulatory treatment, we recorded an income tax benefit that was attributable to the 2008 through 2010 tax years. For years prior to 2008, we did not record a regulatory asset for the repairs deduction as the tax benefit was not flowed through to customers.

At December 31, 2010, we have federal and state NOL carryforwards of $182.6 million and $174.3 million, respectively, which will expire at various dates as follows (in thousands):

Expiration Years	Net Operating Loss Carryforward
2013-2018	$ 1,148
2019-2024	$ 78,177
2025-2030	$ 277,560

As of December 31, 2010, we had a valuation allowance of $1.2 million against the federal NOL carryforwards and $0.5 million against the state 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 will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	2010	2009	2008
Beginning balance at January 1	$ 107,088	$ 120,022	$ 75,770
Additions for prior year tax positions	19,592	5,752	5,015
Reductions for prior year tax positions	(76,545)	(18,686)	(72,948)
Additions for current year tax positions	—	—	112,185
Settlements	—	—	—
Ending balance at December 31	50,135	107,088	120,022
Income tax refund receivable related to uncertain tax positions above	—	(59,136)	(60,612)
Net liability for uncertain tax positions	$ 50,135	$ 47,952	$ 59,410

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $1.7 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in Income tax expense. We recognized the following interest expense for the years ended December 31 as follows (in thousands):

	2010	2009	2008
Interest expense	$ 2,300	$ 1,200	$ 500

We had approximately $3.1 million and $0.8 million accrued for interest payable associated with income taxes at December 31, 2010 and 2009, respectively.

We file income tax returns with the IRS, various state jurisdictions and Canada. We are currently under examination by the IRS for the 2007, 2008 and 2009 tax years. We remain subject to examination by Canadian income tax authorities for tax years as early as 1999.

An agreement was reached during 2010 with the IRS for the 2004, 2005 and 2006 tax years. The agreement involved primarily tax depreciation-related issues with respect to certain assets and resulted in the reversal of the refund receivable related to such issues as indicated above in the tabular roll forward. Instead, the agreement is expected to produce a refund of approximately $16.0 million (including interest) to be received in 2011. 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, 2011.

Excess foreign tax credits have been generated and are available to offset United States federal income taxes. At December 31, 2010, we had the following remaining foreign tax credit carryforwards (in thousands):

Foreign Tax Credit Carryforward	Expiration Year
$ 31	2014
$ 694	2015
$ 940	2016
$ 1,433	2017
$ 254	2020

(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):

2010	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (2,306)	$ 785	$ (1,521)
Fair value adjustment of derivatives designated as cash flow hedges	1,972	(636)	1,336
Reclassification adjustments of cash flow hedges settled and included in net income	(6,730)	2,498	(4,232)
Other comprehensive income (loss)	$ (7,064)	$ 2,647	$ (4,417)

2009	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ 6,922	$ (2,431)	$ 4,491
Fair value adjustment of derivatives designated as cash flow hedges	(27,442)	9,961	(17,481)
Reclassification adjustments of cash flow hedges settled and included in net income	19,810	(7,201)	12,609
Other comprehensive income (loss)	$ (710)	$ 329	$ (381)

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 settled and included in net income	42,710	(14,949)	27,761
Reclassification adjustments for cash flow hedges settled and included in regulatory assets	(5,992)	2,097	(3,895)
Other comprehensive income (loss)	$ 9,022	$ (3,297)	$ 5,725

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

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Amount from Equity-method Investees	Total
As of December 31, 2010	$ (12,437)	$ (11,142)	$ (2)	$ (23,581)
As of December 31, 2009	$ (9,462)	$ (9,636)	$ (66)	$ (19,164)

(16) SUPPLEMENTAL CASH FLOW INFORMATION

Years ended December 31,	2010	2009	2008
		(in thousands)	
Non-cash investing and financing activities-			
Property, plant and equipment acquired with accrued liabilities	$ 48,879	$ 24,571	$ 23,067
Issuance of common stock for earn-out settlement	$ —	$ —	$ 19,694
Refunding bond issuance — Industrial Development Revenue Bonds (see Note 8)	$ —	$ 17,000	$ —
Cash (paid) refunded during the period for-			
Interest (net of amount capitalized)	$ (104,290)	$ (71,891)	$ (55,864)
Income taxes refunded (paid)	$ 315	$ 23,231	$ (32,988)

Cash included in cash balances for discontinued operations is as follows (in thousands):

	December 31, 2010	December 31, 2009	December 31, 2008	December 31, 2007
Ending cash balance includes cash from discontinued operations	$ —	$ —	$ 41	$ 4,366

(17) 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. With the exception of our energy marketing operations in Canada, all of our operations and assets are located within the United States.

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

Utilities Group -

- Electric Utilities, which supply regulated electric utility service to areas in South Dakota, Wyoming, Colorado and Montana and natural gas utility services to Cheyenne, Wyoming and vicinity; and
- Gas Utilities, which supply regulated gas utility service to Colorado, Iowa, Kansas and Nebraska. The regulated Gas Utilities were acquired in July 2008 as described in Note 23.

Non-regulated Energy Group -

- Oil and Gas, which produces, explores and operates oil and natural gas interests located in Colorado, Louisiana, Montana, Oklahoma, New Mexico, North Dakota, Wyoming, Texas and California;
- Power Generation, which produces and sells power and capacity to wholesale customers. During 2010, the power plants were located in Wyoming and Idaho. In 2009 our Power Generation segment entered into a 20-year PPA to supply Colorado Electric with 200 MW of capacity and energy from power plants under construction in Colorado, which are expected to be placed in service by December 31, 2011. Additionally, in January 2011, we sold our ownership interests in the partnerships which own the Idaho facilities;
- Coal Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; and
- Energy Marketing, which provides natural gas, crude oil, coal, power, environmental marketing and related services primarily in the United States and Canada.

On July 11, 2008, we sold entities that owned seven IPP plants. 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 continue to be reported in the Power Generation segment.

On July 14, 2008, we purchased an electric utility and four gas utilities in the Aquila Transaction. The following tables for 2008 report amounts from the acquisition date of July 14, 2008 through December 31, 2008.

Detail for our segments as of and for the year ended December 31 was as follows (in thousands):

	2010	2009
Total assets		
Utilities:		
Electric Utilities	$ 1,834,019	$ 1,659,375
Gas Utilities	722,287	684,375
Non-regulated Energy:		
Oil and Gas	349,991	338,470
Power Generation	293,334	161,856
Coal Mining	96,962	76,209
Energy Marketing	314,930	321,207
Corporate	99,986	76,206
Total assets	$ 3,711,509	$ 3,317,698
Capital expenditures and asset acquisitions		
Utilities:		
Electric Utilities	$ 232,466	$ 241,963
Gas Utilities	51,363	43,005
Non-regulated Energy:		
Oil and Gas	40,345	20,522
Power Generation	148,191	20,537
Coal Mining	17,053	11,765
Energy Marketing	390	220
Corporate	7,182	9,807
Total capital expenditures and asset acquisitions [(a)]	$ 496,990	$ 347,819
Property, plant and equipment		
Utilities:		
Electric Utilities	$ 1,720,909	$ 1,560,851
Gas Utilities	502,360	463,265
Non-regulated Energy:		
Oil and Gas	680,407	668,383
Power Generation	297,907	148,664
Coal Mining	145,385	119,362
Energy Marketing	8,094	2,595
Corporate	4,700	12,873
Total property, plant and equipment	$ 3,359,762	$ 2,975,993

(a) Includes accruals for property, plant and equipment.

	2010	2009	2008
Revenues			
Utilities:			
Electric Utilities	$ 565,577	$ 519,892	$ 472,174
Gas Utilities	550,707	580,312	277,076
Non-regulated Energy:			
Oil and Gas	74,164	70,684	106,347
Power Generation	4,297	4,445	11,893
Coal Mining	31,285	31,459	31,842
Energy Marketing	28,109	13,867	58,660
Corporate	—	—	—
Total revenues	$ 1,254,139	$ 1,220,659	$ 957,992

	2010	2009	2008
Intercompany revenues			
Utilities:			
Electric Utilities	$ 4,437	$ 873	$ 1,245
Non-regulated Energy:			
Power Generation	26,052	26,130	26,288
Coal Mining	26,557	27,031	25,059
Energy Marketing	(110)	(486)	650
Corporate	—	—	267
Intercompany eliminations	(3,824)	(4,629)	(5,711)
Total intercompany revenues[(a)]	$ 53,112	$ 48,919	$ 47,798

(a) In accordance with the accounting standards for regulated operations, intercompany fuel and energy sales to our regulated utilities are not eliminated.

	2010	2009	2008
Depreciation, depletion and amortization			
Utilities:			
Electric Utilities	$ 47,276	$ 43,638	$ 37,648
Gas Utilities	25,258	30,090	14,142
Non-regulated Energy:			
Oil and Gas	30,283	29,680	38,549
Power Generation	4,466	3,860	4,627
Coal Mining	19,083	13,123	9,449
Energy Marketing	527	525	689
Corporate	1	381	2,159
Total depreciation, depletion and amortization	$ 126,894	$ 121,297	$ 107,263

FORM 10K

	2010	2009	2008
Operating income (loss)			
Utilities:			
Electric Utilities	$ 99,292 [(a)]	$ 70,968	$ 77,866
Gas Utilities	68,968 [(b)]	55,210	14,888
Non-regulated Energy:			
Oil and Gas	4,582	(42,521) [(c)]	(71,188) [(c)]
Power Generation	9,673	40,055 [(d)]	14,215
Coal Mining	4,731	5,055	4,293
Energy Marketing	7,259	(423)	30,135
Corporate	(713)	(1,998)	(13,682)
Intercompany eliminations	110	486	(650)
Total operating income	$ 193,902	$ 126,832	$ 55,877

(a) Includes $6.2 million pre-tax gain on sale to the City of Gillette of a 23% ownership interest in the Wygen III power generation facility (See Note 22).
(b) Includes $2.7 million pre-tax gain on the sale of operating assets at Nebraska Gas (See Note 22).
(c) As a result of lower natural gas prices at March 31, 2009, we recorded a $43.3 million pre-tax non-cash ceiling test impairment of oil and gas assets in the first quarter of 2009. As a result of low crude oil and natural gas prices at the end of 2008, we recorded a $91.8 million pre-tax non-cash ceiling test impairment of oil and gas assets (see Note 12).
(d) Includes $26.0 million pre-tax gain on sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility (See Note 22).

	2010	2009	2008
Interest income			
Utilities:			
Electric Utilities	$ 6,812	$ 1,818	$ 2,041
Gas Utilities	1,472	264	376
Non-regulated Energy:			
Oil and Gas	8	10	215
Power Generation	1,193	1,856	8,951
Coal Mining	3,357	1,476	1,392
Energy Marketing	251	787	1,345
Corporate	54,374	27,222	47,425
Intercompany eliminations	(66,773)	(31,821)	(59,569)
Total interest income	$ 694	$ 1,612	$ 2,176
Total interest charges			
Utilities:			
Electric Utilities	$ 43,855	$ 34,830	$ 25,335
Gas Utilities	28,927	17,364	8,501
Non-regulated Energy:			
Oil and Gas	5,380	4,683	5,307
Power Generation	9,303	11,244	20,600
Coal Mining	177	24	46
Energy Marketing	2,450	2,334	1,599
Corporate	69,401	46,032	52,304
Intercompany eliminations	(66,773)	(31,821)	(59,569)
Total interest charges	$ 92,720	$ 84,690	$ 54,123

	2010		2009		2008
Income taxes					
Utilities:					
Electric Utilities	$ 18,012	$	13,126	$	18,882
Gas Utilities	14,449		13,453		2,447
Non-regulated Energy:					
Oil and Gas	(425)		(21,016)		(26,001)
Power Generation	266		11,097		3,013
Coal Mining	2,379		3,234		2,190
Energy Marketing	1,895		(460)		10,180
Corporate	(11,278)		13,881		(40,106)
Intercompany eliminations	—		—		—
Total income tax expense (benefit)	$ 25,298	$	33,315	$	(29,395)
Income (loss) from continuing operations					
Utilities:					
Electric Utilities	$ 47,452 [(a)]	$	32,699	$	39,674
Gas Utilities	27,111 [(b)]		24,372		4,230
Non-regulated Energy:					
Oil and Gas	357		(25,828) [(c)]		(49,668) [(c)]
Power Generation	2,151		20,661 [(d)]		3,251
Coal Mining	7,681		6,748		4,033
Energy Marketing	3,317		(1,488)		19,689
Corporate	(19,494) [(e)]		21,106 [(e)]		(72,596) [(e)]
Intercompany eliminations	110		486		(650)
Total income (loss) from continuing operations	$ 68,685	$	78,756	$	(52,037)

(a) Includes $4.1 million after-tax gain on sale to the City of Gillette of a 23% ownership interest in the Wygen III power generation facility (See Note 22).
(b) Includes $1.7 million after-tax gain on sale of operating assets at Nebraska Gas (See Note 22).
(c) As a result of lower natural gas prices at March 31, 2009, we recorded a $27.8 million after-tax non-cash ceiling test impairment of oil and gas assets in the first quarter of 2009 and as a result of low crude oil and natural gas prices at the end of 2008, we recorded a $59.0 million after-tax non-cash ceiling test impairment of oil and gas assets (see Note 12).
(d) Includes $16.9 million after-tax gain on sale to MEAN of a 23.5% ownership interest in the Wygen I power generation facility (See Note 22).
(e) Includes $9.9 million after-tax net mark-to-market loss for the year ended December 31, 2010, $36.2 million after-tax net mark-to-market gain for the year ended December 31, 2009 and $61.4 million after-tax net mark-to-market loss for the year ended December 31, 2008 for certain interest rate swaps.

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor a 401(k) retirement savings plan. Participants in the Plan may elect to invest a portion of their eligible compensation to the Plan up to the maximum amounts established by the IRS. The Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis. The Plan provides for Company matching contributions and Company Retirement Contributions for certain eligible participants. Vesting of Company contributions ranges from immediate vesting to graduated vesting at 20% per year with full vesting when the participant has five years of service with the Company.

Funded Status of Benefit Plans

The funded status of postretirement benefit plans is required to be recognized 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. Except for our regulated utilities, the unrecognized net periodic benefit cost is recorded within Accumulated other comprehensive income (loss), net of tax. For our regulated utilities, we applied accounting standards for regulated operations, and accordingly, the unrecognized net periodic benefit cost was alternatively recorded as a regulatory asset or regulatory liability, net of tax. As of December 31, 2010, the funded status of our Defined Benefit Pension Plan was $61.0 million; the funded status of our Non-Qualified Defined Benefit Retirement Plan was $25.0 million; and the funded status of our Non-Pension Defined Benefit Postretirement Plan was $42.0 million.

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 Service Company, Black Hills Power, WRDC and BHEP. Effective January 1, 2010, this Plan (with the exception of bargaining unit participants) froze all new non-bargaining unit employees from participation in the Plan and froze the benefits of current non-bargaining participants except for the following group: those non-bargaining unit participants who are both 1) age 45 or older as of December 31, 2009 and have 10 years or more of credited service as of January 1, 2010; and 2) elect to continue to accrue additional benefits under the pension plan and consequently forego the additional age- and points-based employer contribution under the Company's 401(k) retirement savings plan. The assets and obligations for the Black Hills Corporation Plan were revalued July 31, 2009 in conjunction with the freeze of the plan and we recognized a pre-tax curtailment expense of approximately $0.3 million in the third quarter of 2009. In September 2010, the bargaining unit participants in the BHC Pension Plan voted to freeze all new bargaining unit employees from participation in the Plan and to freeze the benefits of current bargaining unit participants except for the following group: those bargaining unit participants who are both 1) age 45 or older as of December 31, 2010 and have 10 years or more of credited service as of January 1, 2011; and 2) elect to continue to accrue additional benefits under the pension plan and consequently fore-go the additional age and points based employer contribution under the Company's 401(k) retirement savings plan. This change to the BHC Pension Plan is effective January 1, 2011. As a result of this freeze, Black Hills Power recognized a pre-tax curtailment expense of less than $0.1 million in the fourth quarter of 2010. BHC Plan benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service.

- The Cheyenne Light Pension Plan covers the bargaining unit employees of Cheyenne Light and benefits 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. In 2009, the Cheyenne Light Plan was amended to freeze the benefits of non-bargaining unit employees. The valuation of the Cheyenne Light Pension Plan at December 31, 2009, resulted in recognition of a pre-tax curtailment expense of less than $0.1 million in the fourth quarter of 2009.

- 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. In 2009, the Black Hills Energy Plan was amended to freeze the Plan to all new participants and froze the benefits of current participants except for the following group: 1) age 45 or older as of December 31, 2009 and have 10 years or more of credited service as of January 1, 2010; and 2) elect to continue to accrued additional benefits under the pension plan and consequently fore-go the additional age and points based employer contributions under the Company's 401(k) retirement savings plan.

Our Pension Plan 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 Investment Policy for the Pension Plans is to seek to achieve the following long-term objectives: 1) a rate of return in excess of the annualized inflation rate based on a five year moving average; 2) a rate of return that meets or exceeds the assumed actuarial rate of return as stated in the Plan's actuarial report; 3) a rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates on a moving three year average, and 4) maintenance of sufficient income and liquidity to pay monthly retirement benefits. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity and fixed income assets. The policy contains certain prohibitions on transactions in separately managed portfolios in which the Pension Plans may invest, including prohibitions on short sales.

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

The expected long-term rate of return for equity investments was 9.25% and 9.50% for the 2010 and 2009 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, 2010, 9.1%, 10.8%, 10.1% and 9.7%, 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 for real estate investments was 6.75%; the return was based on five-year forward-looking return projections from our investment manager for the NCREIF index. The expected long-term rate of return on fixed income investments was 5.75%; the return was based upon historical returns on 10-year treasury bonds of 6.9% from 1962 to 2009, and adjusted for recent declines in interest rates. The expected long-term rate of return on cash investments was estimated to be 1.0%, which was based upon current one-year LIBOR rates plus a credit spread.

Plan Assets

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

	2010	2009
Equity	65 %	65 %
Real estate	3	3
Fixed income	31	28
Cash	1	4
Total	100 %	100 %

Supplemental Non-qualified Defined Benefit Retirement Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit plans. We use a December 31 measurement date for the plans. Effective January 1, 2010, we eliminated a non-qualified pension plan, in which some of our officers participated, due to the partial freeze of our qualified pension plans. We also amended the NQDC, which was adopted in 1999. The NQDC is a non-qualified deferred compensation plan that provides executives with an opportunity to elect to defer compensation and receive benefits without reference to the limitations on contributions in the Black Hills Corporation Retirement Savings Plan or those imposed by the Internal Revenue Code of 1986, as amended. The amended NQDC provides for non-elective non-qualified restoration benefits to certain officers who are not eligible to continue accruing benefits under the Defined Benefit Pension Plans and associated non-qualified pension restoration plans. All contributions to the NQDC plan are subject to a graded vesting schedule at 20% per year over five years with vesting credit beginning with service in the plan on and after January 1, 2010.

Plan Assets

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

Non-pension Defined Benefit Postretirement Plans

We sponsor three retiree healthcare plans (the Plans): the Black Hills Corporation Postretirement Healthcare Plan, the Healthcare Plan for Retirees of Cheyenne Light, 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 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. In July 2009, the Board of Directors approved amendments to the BHC Retiree Healthcare Plan and the Black Hills Energy Plan which changed the structure of the Plans for non-union employees and participating union employees to an RMSA and expanded eligibility of plan participants, effective January 1, 2010. The bargaining unit employees in the Black Hills Corporation Plan voted to change the structure of their benefits to an RMSA effective January 1, 2011.

The benefits for all of the 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 VEBAs, 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.

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 VEBAs. Assets of $4.6 million 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.

Plan Contributions

Contributions to the Healthcare Plans and the Supplemental Plans are made in the form of benefit payments. Contributions to our employee benefit plans were as follows (in thousands):

		2010		2009
Defined Benefit Plans				
Defined Benefit Pension Plans	$	30,015	$	16,945
Non-Pension Defined Benefit Postretirement Healthcare Plans	$	5,198	$	5,113
Supplemental Non-Qualified Defined Benefit Plans	$	894	$	891
Defined Contribution Plans				
Company Retirement Contribution	$	2,022	$	—
Matching contributions - Defined Contribution Plans	$	7,900	$	5,800

We expect to make contributions to our employee benefit plans in 2011 as follows (in thousands):

		2011
Defined Benefit Plans		
Defined Benefit Pension Plans	$	5,190
Non-Pension Defined Benefit Postretirement Healthcare Plans	$	3,590
Supplemental Non-Qualified Defined Benefit Plans	$	940

Fair Value Measurements

Accounting standards for Compensation - Retirement Benefits provide 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 and also requires 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). The pension plans and VEBA 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.

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.

As required by accounting standards for Compensation - Retirement Benefits, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's 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. The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009 (in thousands):

Defined Benefit Pension Plans	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Registered Investment Companies	$ 54,614	$ —	$ —	$ 54,614
103-12 Investment Entities	—	11,247	—	11,247
Common Collective Trust	—	146,080	6,126	152,206
Insurance Contracts	—	2,097	—	2,097
Total investments measured at fair value	$ 54,614	$ 159,424	$ 6,126	$ 220,164

Defined Benefit Pension Plans	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Registered Investment Companies	$ 39,446	$ —	$ —	$ 39,446
103-12 Investment Entities	—	10,611	—	10,611
Common Collective Trust	—	120,602	5,844	126,446
Total investments measured at fair value	$ 39,446	$ 131,213	$ 5,844	$ 176,503

Non-pension Defined Benefit Postretirement Plans	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Common Collective Trust	$ —	$ 4,564	$ —	$ 4,564
Total investments measured at fair value	$ —	$ 4,564	$ —	$ 4,564

Non-pension Defined Benefit Postretirement Plan	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Common Collective Trust	$ —	$ 4,717	$ —	$ 4,717
Total investments measured at fair value	$ —	$ 4,717	$ —	$ 4,717

The following table sets forth a summary of changes in the fair value of the Defined Benefit Pension Plan's level 3 assets for the period ended December 31 (in thousands):

	2010	2009
Balance, beginning of period	$ 5,844	$ 8,300
Unrealized gain (loss)	282	(2,456)
Balance, end of period	$ 6,126	$ 5,844

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the statement of financial position for 2010 and 2009, components of the net periodic expense for the years ended 2010, 2009 and 2008 and elements of accumulated other comprehensive income for 2010 and 2009 (in thousands):

Benefit Obligations

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 256,400	$ 242,545	$ 21,611	$ 22,862	$ 46,396	$ 36,940
Service cost	6,131	7,587	685	469	1,509	1,061
Interest cost	15,091	14,715	1,284	1,376	2,446	2,202
Actuarial (gain) loss	13,663	9,200	2,039	(1,150)	961	12,830
Amendments	261	258	—	22	(2,239)	(3,732)
Benefits paid	(9,949)	(9,002)	(894)	(891)	(5,198)	(5,113)
Plan curtailment reduction	—	(8,081)	—	(1,077)	—	—
Reduction in liability plan freeze	(974)	—	—	—	—	—
Medicare Part D accrued	—	—	—	—	559	555
Equitable asset	—	(822)	—	—	—	—
Plan participants' contributions	—	—	—	—	1,870	1,653
Net increase (decrease)	24,223	13,855	3,114	(1,251)	(92)	9,456
Projected benefit obligation at end of year	$ 280,623	$ 256,400	$ 24,725	$ 21,611	$ 46,304	$ 46,396

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

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Beginning market value of plan assets	$ 176,503	$ 136,899	$ —	$ —	$ 4,717	$ 4,950
Investment income	23,595	33,024	—	—	1	336
Employer contributions	30,015	16,945	—	—	2,493	2,608
Retiree contributions	—	—	—	—	1,205	—
Benefits paid	(9,949)	(9,002)	—	—	(3,847)	(3,177)
Plan administrative expenses	—	(496)	—	—	(5)	—
Equitable asset	—	(867)	—	—	—	—
Ending market value of plan assets	$ 220,164	$ 176,503	$ —	$ —	$ 4,564	$ 4,717

Amounts recognized in the statement of financial position consist of (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Regulatory asset	$ 54,202	$ 53,768	$ —	$ —	$ 7,896	$ 8,660
Current liability	$ —	$ —	$ 943	$ 891	$ 2,999	$ 3,124
Non-current asset	$ —	$ —	$ —	$ —	$ —	$ —
Non-current liability	$ 60,451	$ 79,897	$ 23,782	$ 20,719	$ 38,561	$ 38,554
Regulatory liability	$ —	$ —	$ —	$ —	$ 1,050	$ —

Accumulated Benefit Obligation

(in thousands)	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Accumulated benefit obligation - Black Hills Corporation	$ 90,301	$ 77,948	$ 19,153	$ 17,205	$ 12,101	$ 13,108
Accumulated benefit obligation - Black Hills Energy	$ 160,217	$ 142,012	$ 454	$ 445	$ 25,080	$ 26,329
Accumulated benefit obligation - Cheyenne Light	$ 4,462	$ 3,849	$ —	$ —	$ 9,121	$ 6,959

Components of Net Periodic Expense

(in thousands)	Defined Benefit Pension Plans			Supplemental Non-qualified Defined Benefit Retirement Plans			Non-pension Defined Benefit Postretirement Plans		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Service cost	$ 6,131	$ 7,587	$ 4,720	$ 685	$ 469	$ 447	$ 1,509	$ 1,060	$ 721
Interest cost	15,091	14,715	9,130	1,284	1,376	1,277	2,446	2,202	1,488
Expected return on assets	(14,493)	(14,281)	(10,627)	—	—	—	(208)	(226)	(97)
Amortization of prior service cost	99	127	163	3	1	10	(309)	(23)	—
Amortization of transition obligation	—	—	—	—	—	—	—	60	59
Recognized net actuarial loss (gain)	3,126	2,720	—	285	589	569	636	(27)	(81)
Curtailment expense	57	322	—	—	—	—	—	—	—
Net periodic expense	$ 10,011	$ 11,190	$ 3,386	$ 2,257	$ 2,435	$ 2,303	$ 4,074	$ 3,046	$ 2,090

Accumulated Other Comprehensive Income

In accordance with accounting standards for defined benefit plans, 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 were as follows (in thousands):

	Defined Benefit Pension Plans		Supplemental Nonqualified Defined Benefit Retirement Plans		Non-pension Defined Benefit Postretirement Plans	
	2010	2009	2010	2009	2010	2009
Net (gain) loss	$ 6,545	$ 6,436	$ 4,544	$ 3,429	$ 2,172	$ 2,131
Prior service cost	121	144	14	16	(2,276)	(2,510)
Transition obligation	—	—	—	—	—	—
Total accumulated other comprehensive income	$ 6,666	$ 6,580	$ 4,558	$ 3,445	$ (104)	$ (379)

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 2011 are as follows (in thousands):

	Defined Benefit Pension Plans	Supplemental Nonqualified Defined Benefit Retirement Plans	Non-pension Defined Benefit Postretirement Plans
Net loss	$ 2,951	$ 332	$ 440
Prior service cost	65	2	(312)
Transition obligation	—	—	—
Total net periodic benefit cost expected to be recognized during calendar year 2011	$ 3,016	$ 334	$ 128

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:	2010	2009	2008	2010	2009	2008	2010	2009	2008
Discount rate	5.48 %	6.03 %	6.20 %	4.95 %	5.58 %	6.20 %	5.03 %	5.68 %	6.10 %
Rate of increase in compensation levels	3.79 %	4.20 %	4.25 %	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:	2010	2009	2008	2010	2009	2008	2010	2009	2008
Discount rate:									
Black Hills Corporation	6.05 %	6.25 %	6.35 %	6.10 %	6.20 %	6.35 %	5.90 %	6.10 %	6.35 %
Black Hills Energy	6.00 %	6.25 %	7.00 %	5.05 %	5.00 %	5.00 %	5.15 %	6.10 %	6.75 %
Cheyenne Light	6.05 %	6.20 %	6.35 %	N/A	N/A	N/A	6.00 %	6.10 %	6.35 %
Expected long-term rate of return on assets*	8.00 %	8.50 %	8.50 %	N/A	N/A	N/A	5.00 %	5.00 %	5.00 %
Rate of increase in compensation levels	4.20 %	4.20 %	4.34 %	5.00 %	5.00 %	N/A	NA	N/A	N/A

* The expected rate of return on plan assets changed to 7.75% for the calculation of the 2011 net periodic pension cost.

The healthcare benefit obligation was determined at December 31, 2010, using an initial healthcare trend rate of 9.51% grading down to an ultimate rate of 4.5% in 2027, and at December 31, 2009, using an initial healthcare trend rate of 10.0% trending down to an ultimate rate of 4.5% in 2027.

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 healthcare trend rate for our Retiree Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2010 Accumulated Postretirement Benefit Obligation	Impact on 2010 Service and Interest Cost
Increase 1%	$ 2,437	$ 301
Decrease 1%	$ (2,031)	$ (239)

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
2011	$ 11,387	$ 943	$ 4,210	$ (343)	$ 3,867
2012	12,036	950	4,428	(383)	4,045
2013	12,895	957	4,435	(423)	4,012
2014	13,799	1,084	4,399	(461)	3,938
2015	14,723	1,222	4,365	(504)	3,861
2016-2020	88,740	6,975	21,096	(846)	20,250

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

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

- Black Hills Power's PPA with PacifiCorp, expiring in 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.
- Colorado Electric's PPA with PSCo, expiring in 2011, for 300 MW in 2011. Pricing for the PPA is based on annual contracted capacity and an 85% load factor at current FERC approved rates.
- Black Hills Power has a firm point-to-point transmission service agreement with PacifiCorp that expires in December 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp through 2023.
- Cheyenne Light's PPA with Duke Energy's Happy Jack wind site, expiring in September 2028, provides up to 29.4 MW of wind energy from Happy Jack to Cheyenne Light. Under a separate intercompany agreement, Cheyenne Light sells 50% of the facility output to Black Hills Power.
- Cheyenne Light's PPA with Duke Energy's Silver Sage wind site, expiring in 2029, for 30 MW of wind energy. Under a separate intercompany agreement, Cheyenne Light has agreed to sell 20 MW of energy from Silver Sage to Black Hills Power.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2010	2009	2008
PPA with PacifiCorp	$ 12,936	$ 11,862	$ 11,571
PPA with PSCo	$ 110,575	$ 97,899	$ 57,303
Transmission services agreement with PacifiCorp	$ 1,215	$ 1,215	$ 1,215
PPA with Happy Jack	$ 2,815	$ 2,078	$ 628
PPA with Silver Sage	$ 1,723	$ 713	$ —

Our Gas Utilities also purchase natural gas, including transportation capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2017. On September 29, 2009, FERC approved an extension of a PPA between our subsidiaries, Black Hills Wyoming and Cheyenne Light. The PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility, which was scheduled to expire in 2013, has been extended through December 31, 2022. The agreement includes an option for Cheyenne Light to purchase Black Hills Wyoming's ownership in the Wygen I facility between 2013 and 2019. The purchase price related to the option is $2.55 million per MW which is the equivalent per MW of the estimated price of new construction of the Wygen III plant. This option purchase price is reduced annually by an amount equal to annual depreciation, assuming a facility life of 35 years.

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Long-Term Power Sales Agreements

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

- In conjunction with MDU's April 2009 purchase of 25% ownership interest in Wygen III, an agreement to supply 74 MW of capacity and energy through 2016 was modified. The sales to MDU have been integrated into Black Hills Power's control area and are considered part of our firm native load. MWs from the Wygen III unit are deemed to supply a portion of the required 74 MW. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU;
- In March 2010, Black Hills Power entered into a seven-year PPA and Purchase Option Agreement with the City of Gillette effective April 2010 that replaces a previous agreement. This PPA provided the City of Gillette, with an option to purchase a 23% ownership interest in Black Hills Power's Wygen III facility which commenced commercial operations on April 1, 2010. The City of Gillette exercised its option to purchase the 23% ownership interest in Wygen III and the transaction closed in July 2010. The PPA terminated upon the closing of the transaction. We retain responsibility for operations of the facility with a life-of-plant lease and agreement for operations and coal supply. Black Hills Power entered into an agreement with the City of Gillette to dispatch the City of Gillette's first 23% of net generating capacity. MWs from the Wygen III unit are deemed to supply a portion of the City of Gillette's capacity and energy annually. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23% from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, Black Hills Power will also provide the City of Gillette their operating component of spinning reserves;
- We have a 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. This contract is scheduled to terminate with the commercial operation date of Basin's Dry Fork Generation Station which is scheduled to occur on or about June 30, 2011;
- Black Hills Power has a five-year PPA with MEAN, which commenced on April 1, 2010. Under this contract, MEAN purchases 5 MW of unit-contingent capacity from Neil Simpson II and 5 MW of unit-contingent capacity from Wygen III; and
- In March 2009, our 10-year power sales contract between MEAN and Black Hills Power that originally would have expired in 2013 was re-negotiated and extended until 2023. MEAN will purchase 20 MW of unit-contingent capacity from the Neil Simpson II and Wygen III plants, with capacity purchase decreasing to 15 MW in 2018, 12 MW in 2020 and 10 MW in 2022. The unit-contingent capacity amounts from Wygen III and Neil Simpson II plants are as follows:

2010-2017	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2019	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2021	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

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. Accrued reclamation costs included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $17.6 million and $15.3 million at December 31, 2010 and 2009, respectively.

The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. The amount of accretion expense and depreciation expense for the years ended December 31 was as follows (in thousands):

	2010	2009	2008
Accretion expense	$ 1,246	$ 1,118	$ 639
Depreciation expense	$ 6,519	$ 1,993	$ 580

FORM 10K

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, 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, 2010, cannot be reasonably determined and could have a material adverse effect on the results of operations or financial position.

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 notified the enforcement staff of the FERC of our findings and shared information with the purpose of resolving any potential enforcement concerns. On August 24, 2009, the FERC entered its Order approving a stipulation and consent agreement between the FERC Office of Enforcement and Enserco Energy Inc., which settled all matters presented to the FERC in the 2007 self-report. Pursuant to the Agreement and Order, we agreed to pay a civil penalty of $1.4 million, and submit semi-annual monitoring reports to FERC's Office of Enforcement for one year. The final report was submitted in October 2010. No further enforcement action was taken or is expected relative to the matters presented to the Office of Enforcement. The settlement of this matter, including the payment of a civil penalty by Enserco Energy Inc., did not have a material impact upon our overall consolidated results of operations and cash flows.

(20) 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.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2010	Year Expiring
Guarantee obligations of Enserco under an agency agreement (1)	$ 7,000	2011
Guarantees of payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings (2)	70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP (3)	7,134	2012
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric (4)	5,455	2012
Indemnification for subsidiary reclamation/surety bonds (5)	11,564	Ongoing
Guarantee of payment obligations of Black Hills Utility Holdings for purchase of new office building (6)	6,026	2011
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Black Hills Utility Holdings (7)	9,300	2011
	$ 116,479	

(1) 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 $100.3 million United States dollars (converted from $100.0 million Canadian dollars as of December 31, 2010) of certain transactions involving the buying, selling, transportation and storage of natural gas on behalf of another energy company. The agency agreement terminated on December 31, 2010, but the guarantee remains in place until all obligations have been fulfilled, which is expected in early 2011.

(2) We have guaranteed some 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 regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed some 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 regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

We have guaranteed some 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 regulated gas utilities. The guarantee is a continuing guarantee that may be terminated upon 30 days written notice to the counterparty.

(3) We have issued four guarantees to GE for payment obligations arising from contracts to purchase four LM6000 gas turbines for Black Hills Colorado IPP. These are continuous guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates and completion of the project is scheduled for December 31, 2011. The guarantees will terminate upon settlement of all obligations, which is expected in early 2012.

(4) We have issued two guarantees to GE for payment obligations arising from a contract to purchase two LMS100 natural gas turbine generators by Colorado Electric, which will be used in meeting a portion of the capacity and energy needs of our Colorado Electric customers. These are continuing guarantees which terminate upon payment in full of the purchase price to GE. Payments are scheduled based upon estimated construction milestone dates and completion of the project is scheduled for December 31, 2011. The guarantee will terminate upon settlement of all obligations, which is expected in early 2012.

(5) We have guarantees in place 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.

(6) We issued a guarantee for a payment obligation arising from a contract to construct and purchase a new office building by Black Hills Utility Holdings. The office building is a 36,000 square foot office building located in Papillion, Nebraska. The guarantee will expire upon purchase of the building which is expected to be completed in 2011.

(7) We issued a guarantee to Colorado Interstate Gas Company for payment obligations of Black Hills Utility Holdings related to natural gas transportation, storage and services agreements. The guarantee expires July 31, 2011.

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

BHEP has operating and non-operating interests in 1,314 developed oil and gas wells in ten states and holds leases on approximately 406,200 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):

	2010	2009	2008
Acquisition of properties:			
Proved	$ —	$ —	$ 15,710
Unproved	3,846	3,443	1,290
Exploration costs	8,159	5,962	13,703
Development costs	25,264	10,133	49,441
Asset retirement obligations incurred	1,228	623	5,029
	$ 38,497	$ 20,161	$ 85,173

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using SEC-defined product prices, as of December 31, 2010, 2009 and 2008, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by CG&A. 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. The current estimate takes into account 2010 production of approximately 10.7 Bcfe, additions from extensions and discoveries of 8.6 Bcfe and positive revisions to previous estimates of 14.4 Bcfe, including approximately 19.8 Bcfe due to higher crude oil and natural gas prices.

	2010		2009		2008	
	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	5,274	87,660	5,185	154,432	5,807	172,964
Production	(376)	(8,484)	(366)	(9,710)	(387)	(10,704)
Additions - acquisitions (sales)	(13)	(377)	—	—	2	3,352
Additions - extensions and discoveries	1,145	1,710	152	2,560	438	4,037
Revisions to previous estimates	(90)	14,947	303	(59,622)	(675)	(15,217)
Balance at end of year	5,940	95,456	5,274	87,660	5,185	154,432
Proved developed reserves at end of year included above	4,434	67,656	4,274	74,911	4,429	88,701
NYMEX prices *	$ 79.43	$ 4.38	$ 61.18	$ 3.87	$ 44.60	$ 5.71
Well-head reserve prices	$ 70.82	$ 3.45	$ 53.59	$ 2.52	$ 32.74	$ 4.44

* On December 31, 2008, the SEC issued final rules amending its oil and gas reserve reporting requirements effective for years ended on or after December 31, 2009. The final rule changes the use of prices at the end of each reporting period to prices that are an average of the first day of the month for the preceding twelve months held constant for the life of production.

Reserve additions totaled 8.6 Bcfe, replacing 80% of production. The addition is a result of the development drilling in Williston, San Juan and Powder River basins. Drilling in Williston Basin (Bakken Shale) and San Juan accounted for 8.3 Bcfe of the additions. Williston Basin drilling is planned through 2015. Capital spending in 2010 was increased as Williston Basin drilling resumed. Additionally, exploratory investments were made in 2010 to develop future opportunities. Future capital spending rates are anticipated to increase with improved product prices, resulting in higher anticipated production replacement ratios.

Overall there was an upward revision to reserves totaling 14.4 Bcfe. Most of this revision was a positive 19.8 Bcfe related to higher crude oil and natural gas prices. We experienced positive revisions in the Piceance Basin (15.1 Bcfe) due to higher natural gas prices in the current year compared to the prior year. Additionally, there were positive price revisions in the San Juan, Powder River and other smaller basins in which we have assets. A reduction of lease operating expenses was offset by an increase in future capital costs resulting in a negative revision of 0.8 Bcfe due to costs. We experienced downward revisions due to well performance of 4.6 Bcfe. This performance revision represents approximately 3.5% of the year-end 2010 reserve total. The majority of the downward performance revisions were caused by the elimination of uneconomic PUD locations in the Powder River Basin and Big Horn Basin. In addition, we eliminated uneconomic PUD locations in the San Juan Basin and had minor performance revisions in Piceance, San Juan and Powder River Basins. Partially offsetting the performance-based downward revisions was better than expected drilling results of 2.0 Bcfe from the 2010 development of the Williston Basin.

The SEC adopted new guidelines for reporting reserves in 2009 which amended existing reporting requirements. Characteristics of our reporting are:

- The pricing used to determine reserves must be an average of the first-of-the-month prices over twelve-months instead of a one-day price at the end of the reporting period.

- The SEC established a new definition of "reliable technology" which broadens the technology that a company may use to establish reserves and categories. The new definition permits the use of any reliable technology to establish reserve volumes in addition to those established by production and flow test data. This new definition eliminates previous restrictions limiting allowable PUDs to be booked only one location away from a producing well. We elected to continue with our existing methodology for 2009 and 2010.
- Companies are now permitted but not required to disclose probable and possible reserves. We have elected not to report on these additional reserve categories for 2009 and again in 2010.
- Companies are required to include a narrative disclosure of the total quantity of PUDs at year end, any material changes in PUDs during the year, and investment and progress made in converting the PUDs during the year commencing prospectively from 2009. In 2010, we invested approximately $7.3 million to drill and develop 9 PUD locations from our 2009 inventory totaling approximately 3.6 Bcfe in proved developed reserve recognition. This represents approximately 2.3 Bcfe in PUD conversions with the difference being an upward revision from our 2009 PUD estimates for these same properties based on actual performance. Most of the reserves developed were in the Williston (1.9 Bcfe) and San Juan (1.6 Bcfe) Basins. We have 132 gross PUD locations as of December 31, 2010 located in five basins. These locations represent proved reserves of approximately 36.8 Bcfe, primarily in the Piceance Basin (21.8 Bcfe, 29 gross locations) and Williston Basin (10.9 Bcfe, 28 gross locations). Future development costs associated with these locations are approximately $72.4 million. None of our PUD locations have been reflected in our reserves for five or more years. Consistent with the new SEC guidance, these PUD locations will be monitored and reported each year until they are drilled or revised.

Capitalized Costs

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

	2010	2009	2008
Unproved oil and gas properties	$ 28,160	$ 29,351	$ 31,507
Proved oil and gas properties	592,978	582,276	561,779
	621,138	611,627	593,286
Accumulated depreciation, depletion and amortization and valuation allowances	(334,955)	(335,605)	(267,893)
Net capitalized costs	$ 286,183	$ 276,022	$ 325,393

Results of Operations

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

	2010	2009	2008
Sales Revenues	$ 74,164	$ 70,684	$ 106,347
Production costs	21,922	21,653	31,909
Depreciation, depletion & amortization and valuation provisions*	29,013	72,338	129,597
Total costs	50,935	93,991	161,506
	23,229	(23,307)	(55,159)
Income tax benefit (expense)	(8,014)	8,041	19,306
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ 15,215	$ (15,266)	$ (35,853)

* Includes pre-tax ceiling test impairment charges of $43.3 million and $91.8 million in 2009 and 2008, respectively.

FORM 10K

Standardized Measure of Discounted Future Net Cash Flows

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

	2010	2009	2008
Future cash inflows	$ 764,585	$ 519,867	$ 875,926
Future production costs	(256,455)	(207,783)	(309,169)
Future development costs	(73,805)	(34,961)	(130,632)
Future income tax expense	(111,666)	(51,287)	(100,791)
Future net cash flows	322,659	225,836	335,334
10% annual discount for estimated timing of cash flows	(154,551)	(96,728)	(156,108)
Standardized measure of discounted future net cash flows	$ 168,108	$ 129,108	$ 179,226

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):

	2010	2009	2008
Standardized measure - beginning of year	$ 129,108	$ 179,226	$ 322,898
Sales and transfers of oil and gas produced, net of production costs	(40,282)	(26,836)	(78,342)
Net changes in prices and production costs	57,380	(40,786)	(191,784)
Extensions, discoveries and improved recovery, less related costs	17,076	3,324	7,961
Changes in future development costs	(17,125)	83,000	11,756
Development costs incurred during the period	4,975	4,620	14,306
Revisions of previous quantity estimates	27,513	(104,556)	(41,861)
Accretion of discount	13,434	19,596	42,485
Net change in income taxes	(23,233)	11,520	85,218
Purchases of reserves	—	—	6,592
Sales of reserves	(738)	—	(3)
Standardized measure - end of year	$ 168,108	$ 129,108	$ 179,226

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 all years presented, we had minimal net reserve revisions to prior estimates due to performance. 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, and service availability.

(22) SALE OF OPERATING ASSETS AND DISCONTINUED OPERATIONS

Sale of Operating Assets

Sale of Gas Assets

In March 2010, Nebraska Gas sold assets to Metropolitan Utilities District as a result of annexation proceedings by the City of Omaha, Nebraska. Nebraska Gas received $6.1 million in cash and recognized a $2.7 million gain on the sale.

Partial Sale of Wygen III

On July 14, 2010, Black Hills Power sold a 23% ownership interest in Wygen III to the City of Gillette for $62.0 million. The transaction entitles the City of Gillette to an ownership interest of approximately 25.3 MW in the plant. The purchase terminates the current PPA with the City of Gillette, and the Wygen III Participation Agreement has been amended to include the City of Gillette. The Participation Agreement provides that the City of Gillette will pay Black Hills Power for

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administrative services and share in the costs of operating the plant for the life of the facility. The estimated amount of net fixed assets sold totaled $55.8 million. Black Hills Power recognized a gain on the sale of $6.2 million.

Partial Sale of Wygen I to MEAN

During August 2008, we entered into a definitive agreement to sell a 23.5% ownership interest in the Wygen I plant to MEAN. The sale was completed in January 2009 for a price of $51.0 million, which was based on the then-current replacement cost for the coal-fired plant. We realized an after-tax gain of $16.9 million on the sale, and our property, plant and equipment was reduced by $25.0 million. We retain responsibility for operations of the plant, and at closing entered into a site lease, and operating agreements with MEAN for coal supply and operations. In addition, we terminated a 10-year PPA requiring MEAN to purchase 20 MW of power annually from Wygen I.

Partial Sale of Wygen III to MDU

On April 9, 2009, Black Hills Power sold to MDU a 25% ownership interest in its Wygen III generation facility. At closing, MDU made a payment to us for its 25% share of the costs to date on the ongoing construction of the facility. Proceeds of $32.8 million were received of which $30.2 million was used to pay down a portion of the Acquisition Facility. MDU continued to reimburse Black Hills Power for its 25% of the total costs paid to complete the project. The Wygen III generation facility began commercial operations in April 2010. In conjunction with the sales transaction, we also modified a 2004 PPA between Black Hills Power and MDU. The PPA with MDU now provides that once in commercial operations, the first 25 MW of MDU's required 74 MW will be supplied from its ownership interest in Wygen III. During periods of reduced production at Wygen III, or during periods when Wygen III is offline, MDU will be provided with its 25 MW from our other generation facilities or from system purchases.

Discontinued Operations

Results of operations and the related charges for discontinued operations have been classified as Income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. 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 $142.2 million of which $2.4 million was recorded in 2009 and $139.7 million was recorded in 2008 in discontinued operations. 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):

	2009	2008 *
Operating revenues	$ —	$ 59,572
Pre-tax income from discontinued operations	1,190	27,140
Gain on sale	—	233,599
Income tax benefit (expense)	1,249	(103,758)
Net income from discontinued operations	$ 2,439	$ 156,981

* In accordance with GAAP, during the second quarter of 2008, the Company ceased recording depreciation and amortization expense on the IPP facilities.

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 for the year ended 2008. These allocated costs remain in the Power Generation segment.

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Interest expense included within the operations of the discontinued entities was recorded pursuant to accounting standards for discontinued operations and included interest expense on debt which was required to be repaid as a result of the sale transaction. 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 year ended 2008, interest expense allocated to discontinued operations was $4.7 million.

(23) ACQUISITIONS

Coal Marketing Acquisition

On June 1, 2010, Enserco expanded the commodities it markets through the acquisition of a coal marketing business from EDF for $2.25 million. Substantially all of the value of the net assets acquired was related to the portfolio of coal marketing contracts. On the June 1, 2010 acquisition date, the fair value of the net assets was approximately $2.4 million which was recorded in Derivative assets and Derivative liabilities. Additionally, we recognized a $0.2 million gain from bargain purchase, which was recorded in Other income on the accompanying Consolidated Statements of Income. Since the acquisition, Enserco has recognized $3.6 million of unrealized and realized gains, from coal marketing activities. Further information regarding these coal marketing contracts and activities is included in Note 3 of the Notes to Consolidated Financial Statements.

Aquila Transaction

On July 14, 2008, we acquired one regulated electric utility in Colorado and four regulated gas utilities in Colorado, Kansas, Nebraska and Iowa from Aquila 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. Additionally, approximately $29.6 million of fees and other costs were capitalized as part of the purchase price. The purchase price was financed through our Acquisition Facility and from cash proceeds generated from the IPP Transaction.

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 accounting standards for fair value and reflect significant assumptions and judgments. We comply with the accounting standards for regulated operations 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 were deemed to represent fair values. In accordance with accounting standards for business combinations, adjustments to the purchase price allocation and subsequently goodwill occurred through July 14, 2009.

Adjustments to the purchase price allocation during 2009 included working capital and tax adjustments of $5.4 million.

Allocation of the purchase price is as follows (in thousands):

Current assets	$	113,486
Property, plant and equipment		542,094
Derivative assets		4,695
Goodwill[(a)]		339,028
Intangible assets[(b)]		4,884
Deferred assets		76,143
	$	1,080,330
Current liabilities	$	95,257
Deferred credits and other liabilities		54,550
	$	149,807
Net assets	$	930,523

(a) $245.1 million and $93.9 million of goodwill was allocated to the regulated Electric Utilities and to the regulated 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.

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The results of operations of the acquired regulated utilities have been included in the accompanying Consolidated Financial Statements since the acquisition date.

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 (in thousands, except per share amounts):

	December 31, 2008
Operating revenues	$ 1,548,688
Income (loss) from continuing operations	(27,640)
Net income	129,477
(Loss) earnings per share -	
Basic:	
Continuing operations	$ (0.73)
Total	$ 3.39
Diluted:	
Continuing operations	$ (0.73)
Total	$ 3.39

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.

(24) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth selected unaudited historical operating results and market data for each quarter of 2010 and 2009.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2010				
Operating revenues	$ 442,332	$ 271,291	$ 264,355	$ 329,273
Operating income [(a)]	69,702	30,835	47,942	45,423
Income (loss) from continuing operations [(b)]	31,434	(8,659)	12,390	33,520
Income from discontinued operations, net of taxes	—	—	—	—
Net income (loss) available for common stock	31,434	(8,659)	12,390	33,520
Earnings (loss) per common share:				
Basic —				
Continuing operations	$ 0.81	$ (0.22)	$ 0.32	$ 0.86
Discontinued operations	—	—	—	—
Total	$ 0.81	$ (0.22)	$ 0.32	$ 0.86
Diluted —				
Continuing operations	$ 0.81	$ (0.22)	$ 0.32	$ 0.85
Discontinued operations	—	—	—	—
Total	$ 0.81	$ (0.22)	$ 0.32	$ 0.85
Dividends paid per share	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Common stock prices				
High	$ 30.83	$ 34.49	$ 33.31	$ 33.42
Low	$ 25.65	$ 27.34	$ 27.79	$ 29.32

(a) Includes pre-tax gain on sale of operating assets of $2.7 million ($1.7 million after-tax) and $6.2 million ($4.1 million after-tax) in the first and third quarters, respectively.

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(b) Includes unrealized mark-to-market gain (loss) for interest rate swaps of $(2.0) million, $(16.2) million, $(8.9) million, and $17.2 million after-tax in the first, second, third and fourth quarters, respectively.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2009				
Operating revenues	$ 437,943	$ 257,349	$ 225,799	$ 348,487
Operating income [c]	33,469	25,814	16,909	50,640
Income (loss) from continuing operations [d]	25,625	24,581	(3,853)	32,403
Income (loss) from discontinued operations, net of taxes	766	—	1,673	360
Net income (loss) available for common stock	26,391	24,581	(2,180)	32,763
Earnings (loss) per common share:				
Basic —				
Continuing operations	$ 0.67	$ 0.64	$ (0.10)	$ 0.83
Discontinued operations	0.02	—	0.04	0.01
Total	$ 0.69	$ 0.64	$ (0.06)	$ 0.84
Diluted —				
Continuing operations	$ 0.66	$ 0.64	$ (0.10)	$ 0.84
Discontinued operations	0.02	—	0.04	0.01
Total	$ 0.68	$ 0.64	$ (0.06)	$ 0.85
Dividends paid per share	$ 0.355	$ 0.355	$ 0.355	$ 0.355
Common stock prices				
High	$ 27.84	$ 23.45	$ 26.90	$ 27.98
Low	$ 14.63	$ 17.36	$ 22.57	$ 23.16

(c) Includes ceiling test impairment of $43.3 million pre-tax ($27.8 million after-tax) in first quarter. Includes pre-tax gain on sale of operating assets of $26.0 million ($16.9 million after-tax) in the first quarter.

(d) Includes unrealized mark-to-market income (loss) for interest rate swaps of $9.6 million, $20.6 million, $(5.6) million and $11.6 million after-tax in the first, second, third and fourth quarters, respectively.

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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, 2010. 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 113 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 required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2011 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 48, 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 21 years of experience with the Company.

Scott A. Buchholz, age 49, has been our Senior Vice President — Chief Information Officer since the close of the Aquila Transaction in July 2008. Prior to joining the Company, 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 58, 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 the Company 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. Mr. Cleberg currently sits on the board of directors of CNA Surety.

Linden R. Evans, age 48, has been President and Chief Operating Officer — Utilities since October 2004. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary from December 2003 to October 2004, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has nine years of experience with the Company.

Steven J. Helmers, age 54, has been our Senior Vice President, General Counsel and Chief Compliance Officer since January 2008. He served as our Senior Vice President, General Counsel since January 2004 and our Senior Vice President, General Counsel and Corporate Secretary from 2001 to 2004. Mr. Helmers has 10 years of experience with the Company.

Robert A. Myers, age 53, has been our Senior Vice President — Chief Human Resource Officer 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 59, 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 36 years of experience with the Company. Mr. Ohlmacher has announced his retirement effective March 30, 2011.

Lynnette K. Wilson, age 51, has been our Senior Vice President — Communications and Investor Relations since the close of the Aquila acquisition in July 2008. Prior to joining the Company, 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 11 years.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2011 Annual Meeting of Shareholders, which is incorporated herein by reference.

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 set forth in the Proxy Statement for our 2011 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2010 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	415,533 (1)	$ 32.92 (1)	1,125,958 (2)
Equity compensation plans not approved by security holders	—	—	—
Total	415,533	$ 32.92	1,125,958

(1) Includes 186,572 full value awards outstanding as of December 31, 2010, 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, 265,908 shares of unvested restricted stock were outstanding as of December 31, 2010, which are not included in the above table because they have already been issued.

(2) 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 set forth in the Proxy Statement for our 2011 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2011 Annual Meeting to Shareholders, which is incorporated herein by reference.

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

Schedule I — Condensed Financial Information of the Registrant

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2010, 2009 and 2008.

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.

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SCHEDULE I

BLACK HILLS CORPORATION (PARENT COMPANY)
CONDENSED STATEMENTS OF INCOME

Years ended December 31,	2010	2009	2008
	(in thousands)		
Operating revenues	$ —	$ —	$ —
Operating expenses	735	524	8,978
Operating loss	(735)	(524)	(8,978)
Other income (expense):			
Equity in earnings of subsidiaries	88,627	57,394	174,230
Interest expense	(14,985)	(17,786)	(1,604)
Interest rate swap	(15,193)	55,653	(94,440)
Interest income	22	10	153
Other income	34	28	10
Total other income (expense)	58,505	95,299	78,349
Income from continuing operations before income taxes	57,770	94,775	69,371
Income tax benefit (expense)	10,915	(13,025)	36,586
Income from continuing operations	68,685	81,750	105,957
Loss from discontinued operations	—	(195)	(877)
Net income available for common stock	$ 68,685	$ 81,555	$ 105,080

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

BLACK HILLS CORPORATION (PARENT COMPANY)
CONDENSED BALANCE SHEETS

At December 31,	2010	2009
	(in thousands)	
ASSETS		
Current assets:		
Cash	$ 219	$ 2,273
Accounts receivable — affiliates	869	2,226
Notes receivable — affiliates	201,497	160,160
Deferred income taxes	21,137	15,403
Other current assets	15,173	16,096
Total current assets	238,895	196,158
Investments in subsidiaries	1,269,123	1,101,240
Notes receivable long-term — affiliate	575,000	475,000
Deferred tax assets	44,587	14,501
Other long-term assets	3,889	500
Total other assets	623,476	490,001
TOTAL ASSETS	$ 2,131,494	$ 1,787,399
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,613	$ 1,827
Derivative liabilities, current	57,343	45,129
Notes payable	249,000	164,500
Notes payable — affiliate	25,232	—
Other current liabilities	12,109	7,130
Total current liabilities	345,297	218,586
Derivative liabilities, non-current	7,360	9,075
Long-term debt	674,930	474,901
Note payable long-term — affiliate	3,637	—
Total long-term debt	678,567	474,901
Total stockholders' equity	1,100,270	1,084,837
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,131,494	$ 1,787,399

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

BLACK HILLS CORPORATION (PARENT COMPANY)
STATEMENTS OF CASH FLOWS

Years ended December 31,	2010	2009	2008
	(in thousands)		
Operating activities:			
Net income	$ 68,685	$ 81,555	$ 105,080
Loss from discontinued operations, net of tax	—	195	877
Income from continuing operations	68,685	81,750	105,957
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities —			
Equity in earnings of subsidiaries	(88,627)	(57,394)	(174,230)
Stock compensation	5,849	3,983	2,657
Unrealized mark-to-market (gain) loss on certain interest rate swaps	15,193	(55,653)	94,440
Derivative fair value adjustments	(6,384)	1,461	—
Deferred income taxes	(34,452)	19,224	(32,606)
Other adjustments	2,296	(329)	(926)
Change in operating assets and liabilities —			
Accounts receivable and other current assets	2,198	41,237	(33,342)
Accounts payable and other current liabilities	4,846	(22,906)	5,360
Other operating activities	3,784	1,399	20
Net cash (used in) provided by operating activities of continuing operations	(26,612)	12,772	(32,670)
Net cash used by operating activities of discontinued operations	—	(195)	(877)
Net cash (used in) provided by operating activities	(26,612)	12,577	(33,547)
Investing activities:			
Property, plant and equipment additions	—	—	—
Increase in advances to affiliate	(216,337)	(115,731)	(189,524)
Other investing activities	—	—	(13,500)
Net cash used in investing activities of continuing operations	(216,337)	(115,731)	(203,024)
Net cash used in investing activities of discontinued operations	—	—	—
Net cash used in investing activities	(216,337)	(115,731)	(203,024)
Financing activities:			
Dividends paid on common stock	(56,467)	(55,151)	(53,663)
Common stock issued	3,246	4,819	2,683
Decrease in short-term borrowings	(770,000)	(742,500)	(483,500)
Increase in short-term borrowings	854,500	631,075	788,459
Notes payable to affiliate	14,995	—	—
Long-term debt — issuance	200,000	248,500	—
Other financing activities	(5,379)	1,500	(2,066)
Net cash provided by financing activities of continuing operations	240,895	88,243	251,913
Net cash used in financing activities of discontinued operations	—	—	—
Net cash provided by financing activities	240,895	88,243	251,913
Net change in cash and cash equivalents	(2,054)	(14,911)	15,342
Cash and cash equivalents:			
Beginning of year	2,273	17,184	1,842
End of year	$ 219	$ 2,273	$ 17,184

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Supplemental Cash Flow Information

Years ended December 31,		2010	2009	2008
		(in thousands)		
Non-cash investing and financing activities-				
Non-cash adjustment to notes receivable from affiliate	$	62,019 $	66,034 $	34,473
Non-cash adjustment to notes payable to affiliate	$	13,874 $	— $	—
Non-cash dividend from affiliates	$	— $	225,000 $	225,000
Cash paid (received) during the period for-				
Interest	$	(56,464)$	(19,878)$	(1,376)
Income taxes refunded	$	(504)$	6,667 $	2,278

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

NOTES TO BLACK HILLS CORPORATION (PARENT COMPANY) CONDENSED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Pursuant to rules and regulations of the SEC, the unconsolidated condensed financial statements of Black Hills Corporation do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read in conjunction with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Dividends paid to Black Hills Corporation (the Parent) from its subsidiaries were as follows (in thousands):

		2010	2009	2008
Cash Dividends paid to Parent from subsidiaries	$	6,298 $	— $	—
Non-Cash Dividends paid to Parent from subsidiaries	$	— $	225,000 $	225,000

(2) NOTES PAYABLE

Black Hills Corporation had a committed line of credit with various banks totaling $500.0 million at December 31, 2010 and $525 million at December 31, 2009, respectively. Our credit line is a revolving credit facility, which expires April 14, 2013. We had $149.0 million of borrowings and $46.9 million of letters of credit and $164.5 million of borrowings and $44.8 million of letters of credit issued under the facility at December 31, 2010 and 2009, respectively. The cost of borrowings or letters of credit issued under the facility is determined based on our credit ratings. At current ratings levels, the margins for base rate borrowings, Eurodollar borrowings and letters of credit are 1.75%, 2.75% and 2.75%, respectively at December 31, 2010. The new facility contains a commitment fee to be charged on the unused amount of the facility. Based upon current credit ratings, the fee is 0.5%.

Corporate Term Loan

In December 2010, we entered into a one-year $100.0 million term loan (the "Loan) with J.P. Morgan and Union Bank. The cost of borrowings under the Loan is based on a spread of 137.5 basis points over LIBOR (1.6875% at December 31, 2010). The proceeds were used to reduce borrowings on the Revolving Credit Facility. The covenants are substantially the same as the Revolving Credit Facility.

(3) LONG-TERM DEBT

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

	2010	2009
Senior unsecured notes at 6.5% due 2013	$ 225,000	$ 225,000
Unamortized discount on notes due 2013	(70)	(99)
Senior unsecured notes at 9.0% due 2014	250,000	250,000
Senior unsecured notes at 5.875% due 2020	200,000	—
Total senior unsecured notes	$ 674,930	$ 474,901

Scheduled maturities of long-term debt, excluding amortization of premium or discount, for the next five years are: $225.0 million in 2013 and $250.0 million in 2014.

$200 Million Debt Offering

In July 2010, pursuant to a public offering, we issued $200.0 million aggregate principal of senior unsecured notes due in 2020. The notes were priced at par and carry a fixed interest rate of 5.875%. We received proceeds of $198.7 million, net of underwriting fees. Deferred financing costs of $1.7 million are being amortized over the 10-year term of the debt. Amortization of deferred financing costs is included in interest expense. Proceeds were used to pay down a portion of borrowings on our Revolving Credit Facility and to reduce issued letters of credit.

$250 Million Debt Offering

In May 2009, we issued a $250 million aggregate principal amount of senior unsecured notes due in 2014 pursuant to a public offering. The notes were priced at par and carry a fixed interest rate of 9%. We received proceeds, net of underwriting fees, of $248.5 million. Proceeds were used to pay down the Acquisition Facility. Deferred financing costs capitalized are being amortized over the term of the debt. Amortization of deferred financing costs is included in interest expense.

Certain debt instruments of the Company contain restrictions and covenants, all of which we were in compliance with at December 31, 2010.

(4) 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, 2010, we had the following guarantees in place (in thousands):

Nature of Guarantee	December 31, 2010	Year Expiring
Guarantee obligations of Enserco under an agency agreement	$ 7,000	2011
Guarantees for payment obligations arising from commodity-related physical and financial transactions by Black Hills Utility Holdings	70,000	Ongoing
Guarantees for payment obligations arising from purchase contracts for four gas turbines for Black Hills Colorado IPP	7,134	2012
Guarantees for payment obligations arising from purchase contracts for two gas turbines for Colorado Electric	5,455	2012
Indemnification for subsidiary reclamation/surety bonds	11,564	Ongoing
Guarantee of payment obligations of Black Hills Utility Holdings for purchase of new office building	6,026	2011
Guarantee for payment obligations arising from natural gas transportation, storage and services agreement for Black Hills Utility Holdings	9,300	2011
	$ 116,479	

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(5) RISK MANAGEMENT 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, 2010, we have $150.0 million of notional amount floating-to-fixed interest rate swaps designated as cash flow hedges in accordance with accounting guidance for derivatives and accordingly, the mark-to-market adjustments are recorded in Accumulated other comprehensive loss on the Condensed Balance Sheets of this Schedule I. The swaps have a maximum term of six years.
- 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 accounting guidance for derivatives and the mark-to-market values were recorded in Accumulated other comprehensive loss on the Condensed Balance Sheets of this Schedule I. Based on credit market conditions that transpired during the fourth quarter of 2008, we determined it was probable that the forecasted long-term debt financings would not occur in the time period originally specified and as a result, the swaps were no longer effective hedges and the hedge relationships were de-designated. Mark-to-market adjustments on the swaps are now recorded within the income statement and during 2010 we recorded a $15.2 million pre-tax unrealized mark-to-market loss to earnings, in 2009 we recorded a $55.7 million pre-tax unrealized mark-to-market gain to earnings and in 2008 we recorded a $94.4 million pre-tax unrealized mark-to-market loss to earnings. These swaps are eight and 18 year swaps which have amended mandatory early termination dates ranging from December 15, 2011 to December 29, 2011.

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

	December 31, 2010		December 31, 2009	
	Interest Rate Swaps	De-designated Interest Rate Swaps	Interest Rate Swaps	De-designated Interest Rate Swaps
Notional *	$ 75,000	$ 250,000	$ 150,000	$ 250,000
Weighted average fixed interest rate	4.97 %	5.67 %	4.97 %	5.67 %
Maximum terms in years	6.0	1.0	7.0	1.0
Current derivative assets	$ —	$ —	$ —	$ —
Non-current derivative assets	$ —	$ —	$ —	$ —
Current derivative liabilities	$ 3,363	$ 53,980	$ 6,342	$ 38,787
Non-current derivative liabilities	$ 7,360	$ —	$ 9,075	$ —
Pre-tax accumulated other comprehensive (loss)	$ (10,723)	$ —	$ (15,417)	$ —
Pre-tax gain (loss)	$ —	$ (15,193)	$ —	$ 55,653

* Under the terms of the Black Hills Wyoming project financing, Black Hill Wyoming was required to become a party to hedging agreements fixing the interest rate on $75MM of the principal amount of the debt. To accomplish this, two existing swap agreements were amended so that the Parent and Black Hills Wyoming are now both jointly and severally liable for the full amount of the obligations under the swap agreements. As of January 15, 2010, the mark to market liability associated with the two swaps with a notional value of $75.0 million was transferred from the Parent to Black Hills Wyoming. The balance in AOCI as of January 15, 2010 of the Parent was frozen at that point in time and is being amortized over the remaining life of the swaps through the quarterly settlement process.

Based on December 31, 2010 market interest rates and balances, a loss of approximately $3.4 million would be realized and reported in pre-tax earnings during the next 12 months. Estimated and realized losses will change during the next 12 months as market interest rates fluctuate.

Fair Value Measures

Accounting standards for fair value measurements require, among other things, enhanced disclosures regarding assets and liabilities carried at fair value and also provide 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. Disclosures are required based on 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 their own judgments about the assumptions a market participant would use in pricing the asset or liability.

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 the placement within the fair value hierarchy levels. The following tables set 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 (in thousands):

Liabilities:	Level 1	Level 2	Level 3	Total
December 31, 2010				
Interest rate swaps	$ —	$ 64,703	$ —	$ 64,703
December 31, 2009				
Interest rate swaps	$ —	$ 54,204	$ —	$ 54,204

The following table presents the fair value and balance sheet classification of our derivative instruments as of December 31 (in thousands):

	Balance Sheet Location	December 31, 2010	December 31, 2009
		Fair Value of Liability Derivative	
Derivatives designated as hedges:			
Interest rate swaps	Derivative liability - current	$ 3,363	6,342
Interest rate swaps	Derivative liability - non-current	7,360	9,075
		$ 10,723	$ 15,417
Derivatives not designated as hedges:			
Interest rate swaps	Derivative liability - current	$ 53,980	$ 38,787
		$ 53,980	$ 38,787

FORM 10K

The impact of our cash flow hedges on our Condensed Statement of Income and Balance Sheets for the years ended are presented as follows (in thousands):

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/ (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)
		December 31, 2010	
December 31, 2010			
Interest rate swaps	$ (5,352)	Interest expense	$ (3,662)
December 31, 2009			
Interest rate swaps	$ 12,818	Interest expense	$ (3,228)

The impact of derivative instruments that have not been designated as hedging instruments on our Condensed Statements of Income for the years ended December 31 was as follows (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2010 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swap	(15,193)
Interest rate swaps - realized	Interest expense	(13,312)
		$ (28,505)

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	December 31, 2009 Amount of Gain/(Loss) on Derivatives Recognized in Income
Interest rate swaps - unrealized	Unrealized gain (loss) on interest rate swap	55,653
Interest rate swaps - realized	Interest expense	(9,816)
		$ 45,837

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2010 Carrying Amount	2010 Fair Value	2009 Carrying Amount	2009 Fair Value
Cash	$ 219	$ 219	$ 2,273	$ 2,273
Derivative financial instruments - liabilities	$ 64,703	$ 64,703	$ 54,204	$ 54,204
Notes payable	$ 249,000	$ 249,000	$ 164,500	$ 164,500
Long-term debt	$ 674,930	$ 743,738	$ 474,901	$ 524,673

Derivative Financial Instruments

These instruments are carried at fair value. Additional descriptions of these instruments are included in Note 5 of these Condensed Parent Company Financial Statements on Schedule I.

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 our debt instruments, when available, or debt instruments having similar maturities and similar debt ratings.

(7) COMMON STOCK

Forward Equity Issuance

In November 2010, we entered into a Forward Agreement with J.P. Morgan in connection with a public offering of 4,000,000 shares of Black Hills Corporation common stock. Under the Forward Agreement on November 10, 2010, we agreed to issue to J.P. Morgan 4,000,000 shares of our common stock at an initial forward price of $28.70875 per share.

On December 7, 2010, the underwriters exercised the over-allotment option to purchase an additional 413,519 shares. In conjunction with the underwriters' exercise of the 413,519 share over-allotment option, an additional Equity Forward Agreement was entered into with J.P. Morgan for the over-allotment shares, having the same terms as the original Forward Agreement (together with the Forward Agreement, the "Forward Agreements").

The forward price used to determine cash proceeds due Black Hills Corporation at settlement of the equity forward instruments underlying the Forward Agreements will be calculated based on the November 2010 public offering price of our common stock of $29.75 per share, adjusted for underwriting fees, and interest rate adjustments as specified in the Forward Agreements and expected dividends on our common stock during the period the instrument is outstanding. We may settle the equity forward instrument at any time up to the maturity date of November 10, 2011. We may also unilaterally elect to cash or net share settlement for any date up to maturity, for all or a portion of the equity forward shares.

The equity forward instrument held by J.P. Morgan, underlying the Forward Agreements, was accounted for as equity in accordance with accounting for Derivatives and Hedging - Contracts in Entity's Own Equity, and recorded at fair value at the execution of the Forward Agreements, and will not be subsequently adjusted for changes in fair value until settlement. Since the initial pricing of the equity forward instrument of $28.70875 per share was determined based on the November 2010 offering price of our common stock of $29.75 per share, less underwriting fees of $1.04 per share, no premium on the transaction was due J.P. Morgan related to the Forward Agreements at execution, and no fair value was recorded to equity for the instrument. Proceeds or payments due at settlement of all or portions of the equity forward instrument will be recorded with appropriate adjustments to additional paid in capital and common stock, depending on the method of settlement.

Based on the closing Black Hills Corporation common stock price of $30.00 on December 31, 2010, and the forward price on that date for the equity forward and over-allotment shares of $28.34, the fair value net cash settlement of the 4,000,000 equity forward instrument and 413,519 over-allotment shares was approximately $7.3 million. The Forward Agreements require a 60 day notice prior to settlement for cash or net share settlements. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

At December 31, 2010, the equity forward instrument could have been settled with physical delivery of 4,413,519 shares to J.P. Morgan in exchange for cash of $125.1 million. Assuming required notices were given and actions taken, the forward instruments could have also been settled at December 31, 2010 with delivery of cash of approximately $8.8 million or approximately 291,000 shares of common stock to J.P. Morgan.

(8) COMMITMENTS AND CONTINGENCIES

The Company is subject to various legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the financial position, results of operations or cash flows of the Company.

SCHEDULE II

BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2010, 2009, AND 2008

Description	Balance at Beginning of Year	Adjustments[(a)]	Additions Charged to Costs and Expenses	Other Additions[(b)]	Deductions[(c)]	Balance at End of Year
			(in thousands)			
Allowance for doubtful accounts:						
2010	$ 4,621	$ —	$ 1,930	$ 2,196	$ (6,383)	$ 2,364
2009	$ 6,751	$ —	$ 3,428	$ 3,229	$ (8,787)	$ 4,621
2008	$ 4,588	$ 3,910	$ 3,262	$ 1,789	$ (6,798)	$ 6,751

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

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3. Exhibits

Exhibit Number	Description
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 10-K for 2004).
3.2*	Amended and Restated Bylaws of the Registrant dated January 28, 2010 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 3, 2010).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to 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). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010).
4.2*	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 Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669).
4.3*	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). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008).
10.4†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011.
10.5*†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.6*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.13 to the Registrant's Form 10-K for 2008).
10.7*†	Form of Restricted Stock Award Agreement for Omnibus 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). Form of Restricted Stock Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2008).
10.8*†	Form of Restricted Stock Unit Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.17 to the Registrant's Form 10-K for 2008).

10.9*†	Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2009 (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2008). Form of Performance Share Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2010 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2009).
10.10*†	Form of Short-term Incentive for Omnibus Plan effective for awards granted on or after January 1, 2010. (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2010).
10.11*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).
10.12*†	Indemnification Agreement dated as of May 3, 2010, between Black Hills Corporation and John B. Vering (filed as Exhibit 10.3 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010).
10.13*†	Change in Control Agreement dated September 7, 2010 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on September 10, 2010).
10.14*†	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 September 10, 2010).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008).
10.16†	First Amendment to the Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2011.
10.17*†	Independent Contractor Agreement dated May 3, 2010, between Black Hills Corporation and Lone Mountain Investment, Inc. (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2010).
10.18*†	Consulting Services Agreement between Black Hills Corporation, Thomas M. Ohlmacher and T.O.P., LLC dated December 1, 2010 (filed as Exhibit 10 to the Registrant's Form 8-K filed on December 2, 2010).
10.19*	Credit Agreement, dated as of April 15, 2010 among Black Hills Corporation, as Borrower, The Royal Bank of Scotland Plc. in its capacity as administrative agent for the Banks under the Credit Agreement, and as a Bank, and the other financial institutions party thereto (filed as Exhibit 10 to the Registrant's Form 8-K filed on April 21, 2010).
10.20*	Credit Agreement dated December 15, 2010 among Black Hills Corporation as Borrower, the financial institutions party thereto, as Banks, JPMorgan Chase Bank N.A., as Administrative Agent, and JPMorgan Securities LLC and Union Bank of California N.A., as Co-Lead Arrangers and Joint Book Runner (filed as Exhibit 10 to the Registrant's Form 8-K filed on December 16, 2010).
10.21*	Third Amended and Restated Credit Agreement effective May 8, 2009, among Enserco Energy Inc., as borrower, Fortis Capital Corp., as administrative agent and collateral agent, Societe Generale as Syndication Agent, BNP Paribas as documentation agent, U.S. Bank National Association, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and the other financial institutions which may become parties thereto ("Enserco Credit Agreement") (filed as Exhibit 10.1 to the Registrant's Form 8-K filed October 20, 2009). Joinder Agreements dated May 27, 2009 to the Enserco Credit Agreement (filed as Exhibits 10.1, 10.2 and 10.3 to the Registrant's Form 8-K filed on May 28, 2009). First Amendment to the Enserco Credit Agreement effective August 25, 2009 (filed as Exhibit 10 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2009). Second Amendment to the Enserco Credit Agreement effective December 30, 2009 (filed as Exhibit 10.19 to the Registrant's Form 10-K for 2009). Third Amendment to the Enserco Credit Agreement effective May 7, 2010 (filed as Exhibit 10 to the Registrant's Form 8-K filed May 13, 2010). Joinder Agreement dated May 28, 2010 to the Enserco Credit Agreement (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on June 3, 2010). Fourth Amendment to the Enserco Credit Agreement effective May 28, 2010 (filed as Exhibit 10.2 to the Registrant's Form 8-K filed June 3, 2010). Fifth Amendment to the Enserco Credit Agreement effective July 12, 2010 (filed as Exhibit 10 to the Registrant's Form 8-K filed on July 13, 2010). Sixth Amendment to the Enserco Credit Agreement effective September 21, 2010 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2010).
10.22*	Purchase and Sale Agreement by and between Black Hills Generation, Inc., as Seller, and Southwest Generation Operating Company, LLC, as Buyer, dated as of April 29, 2008 (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 1, 2008).

10.23*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989) -Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989) -Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755) -Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).
10.24*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
10.25*	Confirmation dated November 10, 2010 between the Registrant and J.P. Morgan Securities LLC, as agent for JPMorgan Chase Bank, National Association (filed as Exhibit 1.2 to the Registrant's Form 8-K filed on November 17, 2010). Amendment dated November 15, 2010 to Confirmation dated November 10, 2010 (filed as Exhibit 1.3 to the Registrant's Form 8-K filed on November 17, 2010). Confirmation dated December 7, 2010 (filed as Exhibit 1 to the Registrant's Form 8-K filed on December 10, 2010).
21	List of Subsidiaries of Black Hills Corporation.
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.
99	Report of Cawley, Gillespie & Associates, Inc.
99.1	Mine Safety and Health Administration Safety Data
101	Financials in XBRL Format

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.
(a) See (a) 3. Exhibits above.
(b) 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

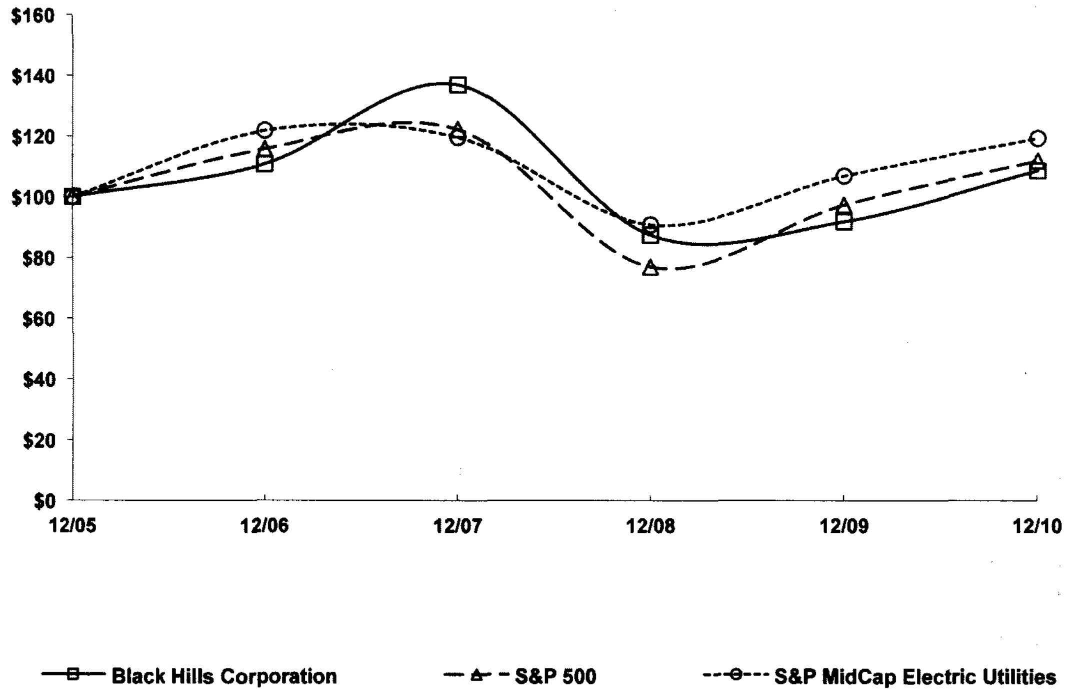
Dated: February 25, 2011

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	February 25, 2011
/S/ ANTHONY S. CLEBERG Anthony S. Cleberg, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 25, 2011
/S/ DAVID C. EBERTZ David C. Ebertz	Director	February 25, 2011
/S/ JACK W. EUGSTER Jack W. Eugster	Director	February 25, 2011
/S/ JOHN R. HOWARD John R. Howard	Director	February 25, 2011
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	February 25, 2011
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	February 25, 2011
/S/ GARY L. PECHOTA Gary L. Pechota	Director	February 25, 2011
/S/ WARREN L. ROBINSON Warren L. Robinson	Director	February 25, 2011
/S/ JOHN B. VERING John B. Vering	Director	February 25, 2011
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	February 25, 2011

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Black Hills Corporation, the S&P 500 Index
and S&P MidCap Electric Utilities



*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

FORM 10K

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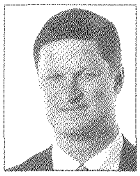
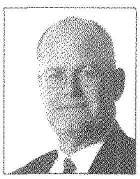
BLACK HILLS CORPORATION BOARD OF DIRECTORS

2010 Annual Report



David R. Emery, age 48, 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 21 years of experience with the Company.



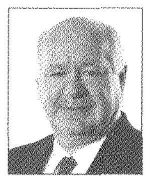
David C. Ebertz, age 65, is President of Dave Ebertz Risk Management Consulting, a firm specializing in insurance and risk management services for schools and public entities, since 2000. He has previous experience in the insurance industry. Mr. Ebertz has served on our Board of Directors since 1998.

Jack W. Eugster, age 65, retired, was Chairman, Chief Executive Officer and President of Musicland Stores, Inc. from 1980 until his retirement in 2001. He was Non-Executive Chairman of Shopko Stores, Inc. a general merchandise discount store chain from 2001 to 2005. Mr. Eugster was elected to the Board of Directors in 2004 and currently chairs the Compensation Committee. He also serves on the board of directors of Donaldson Co., Inc., Graco, Inc., and Life Time Fitness.

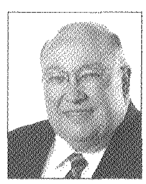
John R. Howard, age 70, retired, was President of Industrial Products, Inc., which provided equipment and supplies to the mining and manufacturing industries, from 1992 to 2003 and was Special Projects Manager for Linweld, Inc. Mr. Howard was elected to the Board of Directors in 1977.

Kay S. Jorgensen, age 60, is involved in numerous business activities and is Owner and Chief Executive Officer of KSJ Enterprises, LLC, providing marketing and development services since 2006. She was Former Owner and Chief Executive Officer of Jorgensen-Thompson Creative Broadcast Services, Inc., a radio broadcast services company, from 1997 to 2005. She previously served in the South Dakota State Legislature and on various state and local boards and commissions. She served on the board of Wellmark, Inc. from 2002 to 2009, and on the board of Wellmark Blue Cross Blue Shield of South Dakota from 1999 to 2010. Ms. Jorgensen has served on the Board of Directors since 1992.

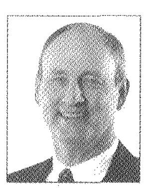
Stephen D. Newlin, age 58, is Chairman, President and Chief Executive Officer of PolyOne Corporation, a global premier provider of specialized polymer materials, services and solutions, since 2006. Prior to that he was President of the Industrial Sector of Ecolab, Inc., a global leader of services, specialty chemicals and equipment serving industrial and institutional clients, from 2003 to 2006. Mr. Newlin was elected to the Board of Directors in 2004 and currently chairs the Governance Committee. He also serves on the board of directors of Valspar Corporation.



Gary L. Pechota, age 61, is President and Chief Executive Officer of DT-TRAK Consulting, Inc., a medical billing services company, since December 2007. He was retired from 2005 to 2007. Prior to that he was Former Chief of Staff of the National Indian Gaming Commission from 2003 to 2005. He previously held executive positions in the cement industry and positions in finance and accounting. Mr. Pechota was elected to the Board of Directors in 2007. He also serves on the board of directors of Insteel Industries, Inc. and Texas Industries, Inc.



Warren L. Robinson, age 61, retired, was Executive Vice President, Treasurer and Chief Financial Officer of MDU Resources Group, Inc., a diversified energy and resources company, from 1992 until his retirement in January 2006. Mr. Robinson was elected to the Board of Directors in 2007 and currently chairs the Audit Committee. He also serves on the board of directors of TMI Systems Design Corporation.



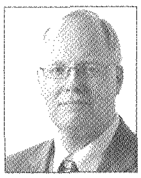
John B. Vering, age 61, has been serving as Interim President and General Manager of Black Hills Exploration and Production, Inc., our oil and gas subsidiary, since May 2010. He has also been Managing Director of Lone Mountain Investments, Inc., agricultural and oil and gas investments, since 2002. He previously held several executive positions in the oil and gas industry. Mr. Vering was elected to the Board of Directors in 2005. He also serves on the board of directors of Broad Oak Energy, Inc.

Thomas J. Zeller, age 63, has been Chief Executive Officer of RESPEC, a technical consulting and services firm with expertise in engineering, information technologies and water and natural resources since Jan. 2011 and served as President from 1995 to Jan. 2011. Mr. Zeller has been a member of the Board of Directors since 1997 and currently serves as Presiding Director.

BLACK HILLS CORPORATION EXECUTIVE OFFICERS

2010 Annual Report

David R. Emery, age 48, 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 21 years of experience with the Company.

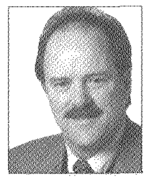


Scott A. Buchholz, age 49, has been our Senior Vice President — Chief Information Officer since the close of the Aquila Transaction in July 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from June 2005 until July 2008, Six Sigma Deployment Leader/Black Belt 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 58, 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 the Company 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. Mr. Cleberg currently sits on the board of directors of CNA Surety.

Linden R. Evans, age 48, has been President and Chief Operating Officer — Utilities since October 2004. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary from December 2003 to October 2004, and served as our Associate Counsel from May 2001 to December 2003. Mr. Evans has nine years of experience with the Company.

Steven J. Helmers, age 54, has been our Senior Vice President, General Counsel and Chief Compliance Officer since January 2008. He served as our Senior Vice President, General Counsel since January 2004 and our Senior Vice President, General Counsel and Corporate Secretary from 2001 to 2004. Mr. Helmers has 10 years of experience with the Company.



Robert A. Myers, age 53, has been our Senior Vice President — Chief Human Resource Officer 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 59, 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 36 years of experience with the Company. Mr. Ohlmacher retired March 31, 2011.

Lynnette K. Wilson, age 51, has been our Senior Vice President — Communications and Investor Relations since the close of the Aquila acquisition in July 2008. Prior to joining the Company, 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 11 years.

INVESTOR INFORMATION

2010 Annual Report

Common Stock
Transfer Agent, Registrar & Dividend Disbursing Agent
Wells Fargo Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
800-468-9716
www.wellsfargo.com/shareownerservices

Senior Unsecured Notes – Black Hills Corporation
Trustee & Paying Agent
Wells Fargo Bank, N.A.
201 Main Street, Suite 301
Fort Worth, Texas 76102

First Mortgage Bonds – Black Hills Power, Inc.
The Bank of New York Mellon
101 Barclay Street, 8W
New York, New York 10286

First Mortgage Bonds – Cheyenne Light, Fuel & Power
Trustee & Paying Agent
Wells Fargo Bank, N.A.
201 Main Street, Suite 301
Fort Worth, TX 76102

Pollution Control Refunding Revenue Bonds – Black Hills Power, Inc.
Trustee & Paying Agent
Wells Fargo Bank, N.A.
625 Marquette Ave., 11th floor
Minneapolis, Minnesota 55479

Environmental Improvement Revenue Bonds – Black Hills Power, Inc.
Trustee & Paying Agent
The Bank of New York Mellon
1775 Sherman Street, Suite 2775
Denver, Colorado 80203

Industrial Development Revenue Bonds – Cheyenne Light, Fuel & Power
Trustee & Paying Agent
US Bank National Association
950 17th Street, Suite 1200
Denver, Colorado 80202

Corporate Offices
Black Hills Corporation
P.O. Box 1400
625 Ninth Street
Rapid City, South Dakota 57709
605-721-1700
www.blackhillscorp.com

2011 Annual Meeting
The Annual Meeting of Shareholders will be held at The Dahl Arts Center, 713 Seventh Street, Rapid City, South Dakota, at 9:30 a.m. local time on May 25, 2011. Prior to the meeting, formal notice, proxy statement and proxy will be mailed to shareholders.

Market for Equity Securities
The Company's Common Stock ($1 par value) is traded on the New York Stock Exchange (NYSE). Quotations for the Common Stock are reported under the symbol BKH. The continued interest and support of equity owners are appreciated. The Company has declared Common Stock dividends payable in each year since its incorporation in 1941. Regular quarterly dividends when declared are normally payable on March 1, June 1, September 1 and December 1.

Internet Account Access
Registered shareholders can access their accounts electronically at www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and much more. The transfer agent maintains stockholder account access.

Direct Deposit of Dividends
We encourage you to consider the direct deposit of your dividends. With direct deposit, your quarterly dividend payment can be automatically transferred on the dividend payment date to the bank, savings and loan, or credit union of your choice. Direct deposit assures payments are credited to shareholders' accounts without delay. A form is attached to your dividend check where you can request information about this method of payment. Questions regarding direct deposit should be directed to Wells Fargo Shareowner Services.

Dividend Reinvestment and Direct Stock Purchase Plan
A Dividend Reinvestment and Direct Stock Purchase Plan provides interested investors the opportunity to purchase shares of the Company's Common Stock and to reinvest all or a percentage of their dividends. For complete details, including enrollment, contact the transfer agent, Wells Fargo Shareowner Services. Plan information is also available at www.wellsfargo.com/shareownerservices.

Website Access to Reports
The reports we file with the SEC are available free of charge at our web site 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 web site 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.

Black Hills Corporation

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www.blackhillscorp.com

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