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

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

For the fiscal year ended December 31, 2003

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

For the transition period from ___________________ to __________________

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

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

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

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

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

YES __X__ NO____

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.

X

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

YES __X__ NO____

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

At June 30, 2003 $977,471,987

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 February 29, 2004
Common stock, $1.00 par value	32,297,298 shares

Documents Incorporated by Reference

1. Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2004 Annual Meeting of Stockholders to be held on May 26, 2004, are incorporated by reference in Part I, Item 4A and Part III of the Form 10-K.

TABLE OF CONTENTS

PART I

ITEMS 1 AND 2.   BUSINESS AND PROPERTIES

Website Access to Reports

Through our Internet website, www.blackhillscorp.com, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

General

We are a diversified energy holding company operating principally in the United States with three major business groups: wholesale energy, electric utility and communications. Our Wholesale Energy group engages in the production and sale of electric power through ownership of a diversified portfolio of generating plants; the production of coal, natural gas and crude oil primarily in the Rocky Mountain region; and the marketing and transportation of fuel products. Our electric utility group engages in the generation, transmission and distribution of electricity to an average of approximately 61,000 customers in South Dakota, Wyoming and Montana. Our communications group offers a full suite of broadband telecommunications services, including local and long distance telephone services, expanded cable television service, cable modem Internet access and high speed data and video services, to approximately 26,890 residential and business customers located in Rapid City and the Northern Black Hills region of South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941 and began selling and marketing various forms of energy on an unregulated basis in 1956.

As the following table illustrates, we have experienced significant change over the last five years, primarily as a result of the expansion of our wholesale energy business and increases in wholesale electric sales at our electric utility. Unusual conditions in the Western energy markets during the first half of 2001 and the latter part of 2000 accounted for approximately $1.40 per share and $0.40 per share of our earnings in 2001 and 2000, respectively.

	2003	2002	2001	2000	1999
Net income available for common (in thousands):					
Wholesale energy	$ 41,162	$ 39,513	$ 54,457	$ 28,511	$ 12,554
Electric utility	24,089	30,217	45,238	37,178	27,362
Communications	(5,880)	(7,260)	(12,300)	(11,382)	(968)
Corporate expenses and intersegment eliminations	(7,829)	(3,218)	(3,811)	(2,441)	(1,210)
Discontinued operations	9,422	1,977	3,966	904	(671)
	$ 60,964	$ 61,229	$ 87,550	$ 52,770	$ 37,067
Earnings per share - diluted	$ 1.97	$ 2.26	$ 3.42	$ 2.37	$ 1.73
Total assets (in thousands)	$2,063,225	$1,999,974	$1,651,765	$1,252,936	$ 664,863
Capital expenditures (in thousands)	$ 116,691	$ 303,918	$ 594,142	$ 173,517(1)	$ 152,948
Generating capacity (megawatts)					
Utility (owned generation)	435	435	395	393	353
Utility (purchased capacity)	55	60	65	70	75
Independent power generation (2)	1,002	950(3)	617	250	--
Total generating capacity	1,492	1,445	1,077	713	428
Utility electric sales (megawatt-hours):					
Firm electric sales	1,994,819	1,966,060	2,012,354	1,973,066	1,920,005
Wholesale off-system	930,706	979,677	965,030	684,378	445,712
Total utility electric sales	2,925,525	2,945,737	2,977,384	2,657,444	2,365,717
Oil and gas reserves (Mmcfe)	156,399	57,793	48,401	44,882	44,114
Oil and gas production sold (Mmcfe)	10,843	7,398	7,293	5,278	4,698
Tons of coal sold (thousands of tons)	4,812	4,052	3,518	3,050	3,180
Average daily marketing volumes:					
Natural gas (MMbtus)	1,241,900	1,088,200	1,047,700	860,800	635,500
Crude oil (barrels)	58,700	57,200	36,500	44,300	19,270
Communications:					
Residential customers	23,878	21,700	15,660	8,368	143
Business customers	3,012(4)	3,061	2,250	646	110
Fiber optic backbone miles	245	242	242	210	200
Hybrid fiber coaxial cable miles	840	818	737	588	100

(1) Excludes the non-cash acquisition of Indeck Capital, Inc.
(2) Includes 40 MWs in 2003, 82 MWs in 2002, 68 MWs in 2001 and 58 MWs in 2000, which are currently reported as “Discontinued operations”.
(3) Includes the 224 megawatt expansion at the Las Vegas cogeneration power plant that was placed in service on January 3, 2003.
(4) In 2003, reported business customers were adjusted for consolidation of multiple-location business customers, business orders and temporary business access lines.

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 18 of NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

Industry Overview

The energy and telecommunications industries are expected to become increasingly competitive due to a variety of regulatory, economic and technological changes.

In the last decade, many U.S. regulatory bodies took steps to transform the energy sectors which they regulate to encourage competition, introduce customer choice and, in some cases, to improve the operational performance of strategic energy assets. As a result of regulatory initiatives at the federal and state levels, the electric power industry has experienced and is undergoing substantial change. As early as the mid-1990's, new regulatory initiatives to increase competition in the domestic power generation industry were adopted or were being considered. The primary focus of such efforts was to increase competition through the disaggregation of the traditional utility functions of generation, transmission, distribution and marketing of electricity. These changes created new investment opportunities for competitive or partially regulated businesses to enter previously non-competitive or closed markets.

The electric power industry also witnessed growing consumer demand and frequent regional shortages of electricity over the past several years. The summers of 1998, 1999 and 2000 and the winter of 2000-2001 were characterized by very high peak prices for electricity in a number of recently deregulated wholesale electricity markets. In a number of these markets, government agencies and other interested parties made proposals to delay market restructuring or even re-regulate certain areas of the markets that had been previously deregulated. The Federal Energy Regulatory Commission (FERC) instituted a series of price controls designed to mitigate (or cap) prices in the Western United States and initiated numerous investigations into the Western electric and gas markets as a result of the 2000-2001 California energy crisis. These price controls contributed to the lowering of spot and forward energy prices in the Western markets. Other proposals to re-regulate the energy industry or to institute price controls may be made, and legislative or other actions may cause the electric power restructuring process to be delayed, discontinued or reversed in states that have already deregulated. Mild weather patterns in the summer of 2001 and winter of 2001-2002, an economic recession and recent modest recovery mitigated most regional energy shortages.

The energy industry experienced a financial crisis beginning in late 2001 stemming from the collapse of Enron Corporation and the near collapse of several other leading energy companies. The cumulative market capitalization of energy companies fell on the scale of hundreds of billions of dollars, reflecting challenging market conditions and investor attitudes. Investors and consumers lost confidence in the financial health and future prospects of many energy providers as a result of numerous events. Accordingly, energy companies have been subject to much greater scrutiny by regulators, credit rating agencies and investors. In response, companies are moving aggressively to improve liquidity and to restructure their balance sheets. They are abandoning unsuccessful business strategies, selling non-core assets, downsizing staffs, issuing new equity, canceling acquisitions, postponing or canceling construction projects, reducing significant levels of capital expenditures, accelerating debt repayment and realigning trading around their own generation, mid-stream and transportation assets.

The oil and gas industry has experienced significant commodity price volatility in recent years. Price increases in 2000 and again in 2003 were driven in part by several years of accentuated "boom and bust" cycles of drilling activity, combined with strong growth in demand for energy commodities and continued unrest in the Middle East. Price decreases in 2002 were driven by weather patterns, a recession and actions by OPEC. Natural gas is expected to remain the national fuel of choice. Demand for natural gas is expected to be strong in the future as industrial consumption rises and as more gas-fired power plants are brought into service.

The telecommunications industry underwent widespread changes brought about by, among other things, the Telecommunications Act of 1996, the decisions of federal and state regulators to open the monopolistic local telephone and cable television markets to competition, increased consumer demand for higher speed and higher capacity networks and for expanded telecommunications services, including broader video choices and high speed data and Internet services. The convergence of these trends allowed many new entrants into the telecommunications market. More recently the telecommunications industry suffered the effects of an economic slowdown, increased competition and financial stress.

Our Business Strategy

Our long-term strategy is to add and augment revenue streams from our diversified energy operations. We have implemented a balanced, integrated approach to fuel production, energy marketing, power generation and retail operations, supported by disciplined risk management practices. Building on the strength of our electric utility, we enhanced our local operations by providing broadband communications to our customers in South Dakota. Our diverse operations avoid reliance on any single business to achieve our strategic objectives. This diversity is expected to provide a measure of stability to our business and financial performance in volatile or cyclical periods.

Our strategy includes the following key elements:

- grow our power generation segment by developing and acquiring power generating assets in targeted Western markets and, in particular, by expanding generating capacity of our existing sites through a strategy known as “brownfield development;"
- sell a large percentage of our capacity and energy production from new independent power projects through mid- and long-term contracts in order to secure a stable revenue stream and attractive returns;
- preserve our electric utility’s low-cost rate structure for our residential, commercial and industrial customers while retaining the flexibility to selectively market excess generating capacity off-system to maximize returns in changing market environments;
- expand retail operations through selective acquisitions of electric utilities consistent with our regional focus and strategic advantages;
- increase our reserves of natural gas and crude oil and expand our overall fuel production;
- grow our energy marketing operations primarily through the expansion of producer and end-use origination services;
- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure;
- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;
- exploit our fuel cost advantages and our operating and marketing expertise to produce power at attractive margins;
- increase margins from our coal production through an expansion of mine-mouth generation and increased coal sales;
- build and maintain strong relationships with wholesale energy customers;
- create a stronger and financially viable communications business segment by continuing to capitalize on our utility’s established market presence and reputation for customer service and value, by increasing revenues and by creating additional operating efficiencies; and
- organize our lines of business into retail and wholesale energy components. The retail component will consist of electric and telecommunications products and services. The wholesale component will consist of fuel production, marketing, mid-stream assets and power production facilities.

Grow our Power Generation Segment by Developing and Acquiring Power Generating Assets in Targeted Western Markets, and in Particular, by Expanding Generating Capacity of our Existing Sites Through a Strategy Known as "Brownfield Development." We aim to develop power plants in regional markets based on prevailing supply and demand fundamentals in a manner that complements our existing fuel assets and fuel and energy marketing capabilities. This approach seeks to capitalize on market growth while managing our fuel procurement needs. Over the next few years, we intend to grow through a combination of disciplined acquisitions and development of new power generation facilities primarily in the Western region where we believe we have the detailed knowledge of market fundamentals and competitive advantage to achieve attractive returns. We believe the following trends will provide us with growth opportunities in the future:

- Demand for electricity in certain Western regions is expected to grow and new generation capacity will be required over the next several years.
- New electric generation construction will be predominantly gas-fired, which may create further competitive cost advantages for new and existing coal-fired generation assets.
- Transmission construction will significantly lag new generation development, favoring new development located near load centers or existing, unconstrained transmission locations.
- Disaggregation of the electric utility industry from traditionally vertically integrated utilities into separate generation, transmission, distribution and marketing entities may continue in certain regions, thereby creating opportunities for expansions, acquisitions and joint ventures.

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

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

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

Sell a Large Percentage of our Capacity and Energy Production From New Independent Power Projects Through Mid- and Long-Term Contracts in Order to Secure a Stable Revenue Stream and Attractive Returns. By selling the majority of our energy and capacity under mid- and long-term contracts, we believe that we can satisfy the requirements of our customers while earning more stable revenues and greater returns over the long term than we could by selling our energy into the more volatile spot markets. When possible, we structure long-term contracts as tolling arrangements, whereby the contract counterparty assumes the fuel risk. Our goal is to sell approximately 80-90 percent of our unregulated power generation assets under long-term contracts.

Preserve our Electric Utility's Low-Cost Rate Structure for our Residential, Commercial and Industrial Customers While Retaining the Flexibility to Selectively Market Excess Generating Capacity Off-System to Maximize Returns in Changing Market Environments. In 1999, the South Dakota Public Utilities Commission extended our previous retail rate freeze until January 1, 2005. The rate freeze preserves our low-cost rate structure at levels below the national average for our retail customers while allowing us to retain the benefits from cost savings and wholesale "off-system" sales. This provides us with flexibility in allocating our generating capacity to maximize returns in changing market environments. We have historically optimized the utilization of our power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts.

Expand Retail Operations Through Selective Acquisitions of Electric Utilities Consistent with our Regional Focus and Strategic Advantages. For more than 60 years, we have provided strong retail services, based on delivering quality and value to our customers. That tradition and accomplishment is expected to support efforts to expand our retail operations in other markets, most likely in the West and in regions that permit us to take advantage of our intrinsic competitive advantages, such as baseload power generation and system reliability. Retail operations also can augment other important business development, including transmission and pipelines and storage infrastructure, which could lead to advancing other wholesale operations. Regulated retail operations can contribute substantially to the stability of our long-term cash flows and earnings.

Increase our Reserves of Natural Gas and Crude Oil and Expand our Overall Fuel Production. Our strategy is to expand our natural gas reserves through a combination of acquisitions and drilling programs. We aim to maintain sufficient natural gas production either to directly serve or indirectly hedge the fuel cost exposure of our gas-fired generation plants. Specifically, we plan to:

- substantially increase our natural gas reserves while minimizing exploration risk by focusing on lower-risk exploration and development drilling as well as acquisitions of proven reserves;

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

- add natural gas reserves and increase production by focusing primarily on various shallow gas plays in the Rocky Mountain region, where the added production can be integrated with our fuel marketing and/or power generation activities.

Grow our Energy Marketing Operations Primarily Through the Expansion of Producer and End-use Origination Services. Our energy marketing activities distinguish themselves from other marketing businesses by focusing on customer services and the physical delivery of energy commodities. With our producer services, we primarily assist natural gas producers in the Rocky Mountain region of the U.S. and Canada with marketing and transporting their commodities to the marketplace. We also provide origination services, where we work with industrial consumers of natural gas, by sourcing and arranging delivery for gas. We expect, because of our regional marketing expertise and proven knowledge of efficiently utilizing storage and transportation infrastructure, that we can increase our marketing volumes. In the future, we may acquire additional mid-stream assets, such as regional pipelines and storage systems, so that we can facilitate and further augment our marketing services.

Manage the Risks Inherent in Energy Marketing by Maintaining Position Limits That Minimize Price Risk Exposure. Our energy marketing operations require effective management of price and operational risks related to adverse changes in commodity prices and the volatility and liquidity of the commodity markets. To mitigate these risks, we have implemented risk management policies and procedures for each of our marketing companies that establish price risk exposure levels. We formed oversight committees to monitor compliance with our policies. We also limit exposure to energy marketing risks by maintaining separate credit facilities for each of our marketing companies.

Conduct Business with a Diversified Group of Creditworthy or Sufficiently Collateralized Counterparties. Our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diversified group of creditworthy counterparties. In certain cases where creditworthiness merits security, we require prepayment, secured letters of credit or other forms of financial collateral. We accomplish this by establishment of counterparty credit limits, continuous credit monitoring, and regular review of credit compliance with our policy by our Executive Credit Committee that reports to our board of directors.

Exploit our Fuel Cost Advantages and our Operating and Marketing Expertise to Produce Power at Attractive Margins. We expect to expand our portfolio of power plants having relatively low marginal costs of producing energy and related products and services. As an increasing number of gas-fired power plants are brought into operation, we intend to utilize a low-cost power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream. Low marginal production costs can result from a variety of factors, including low fuel costs, efficiency in converting fuel into energy, and low per unit operation and maintenance costs. We aggressively manage each of these factors with the goal of achieving very low production costs.

Our primary competitive advantage is our coal mine, which is located in close proximity to our retail service territory. We are exploiting the competitive advantage of this native fuel source by building additional mine-mouth coal-fired generating capacity. This strengthens our position as a low-cost producer since transportation costs often represent the largest component of the delivered cost of coal.

Increase Margins From our Coal Production Through an Expansion of Mine-Mouth Generation and Increased Coal Sales. Our strategy is to expand our coal production through the construction of mine-mouth coal-fired generation plants at our Wyodak mine location. Our objective is to maintain coal reserves to serve our mine-mouth coal-fired generation plants directly. Specifically, we plan to:

- increase coal production and sales from our Wyodak mine by continuing to develop additional mine-mouth generating facilities at the site; and

- pursue future sales of coal from the Wyodak mine to regional rail-served customers.

Build and Maintain Strong Relationships With Wholesale Energy Customers. We strive to build strong relationships with utilities, municipalities and other wholesale customers, who we believe will continue to be the primary providers of electricity to retail customers in a deregulated environment. We further believe that these entities will need products, such as capacity, in order to serve their customers reliably. By providing these products under long-term contracts, we are able to meet our customers' energy needs. Through this approach, we also believe we can earn more stable revenues and greater returns over the long term than we could by selling energy into the more volatile spot markets.

Create a Stronger and Financially Viable Communications Business Segment by Continuing to Capitalize on our Utility's Established Market Presence and Reputation for Customer Service and Value by Increasing Revenues, and by Creating Additional Operating Efficiencies. In just five years, we have advanced a broadband communications startup into the dominant provider of telephone, cable television and high-speed Internet services in the areas we serve. This accomplishment was initially due to the strength of our utility's reputation for reliability, customer service and value. More recently, our improvement in operations is due primarily to our service deliverability, reliability and commitment to our broadband customers. We believe this dual strategy – upholding our strong public standing and delivering superior broadband communications products and services – will advance our efforts further in the future. As we continue to seek additional customers and revenue, we will also continue efforts to create operating efficiencies by integrating appropriate business functions with related utility operations, benefiting both business segments.

Wholesale Energy

Our wholesale energy group engages in the production of electric power through ownership of a diversified portfolio of generating plants and the sale of electric power primarily under long-term contracts, the production of coal, natural gas and crude oil primarily in the Rocky Mountain region, and the marketing of energy products. The wholesale energy group consists of four segments: power generation, natural gas and crude oil production, coal mining and energy marketing and transportation.

Power Generation

Our power generation segment acquires, develops, expands and operates unregulated power plants. We currently hold varying interests in independent power plants in Colorado, Nevada, Wyoming, California and Massachusetts with a total net ownership of 1,002 megawatts in operation, including minority interests in several power-related funds with a net ownership interest of 28 megawatts and a 40 megawatt plant in Massachusetts currently held for sale.

Project Development Program. Through our active acquisition and development program we are pursuing a number of additional generation projects in the early stages of development, including a coal-fired mine-mouth power plant(s) with a total generating capacity of up to 500 megawatts, to be located at our Wyodak site near Gillette, Wyoming. We cannot assure you that we will be successful in completing any or all of the projects currently under consideration.

How We Manage Our Portfolio. We strive to maintain diversity and balance in our portfolio of regulated and unregulated power plants. Our unregulated portfolio is diversified in terms of fuel mix and geographic location, with approximately 90 percent of net unregulated capacity being gas-fired and the remainder coal-fired. Our independent power plants are located in Colorado, Nevada, Wyoming, California and Massachusetts (which is planned for sale). By comparison, our electric utility capacity is approximately 50 percent coal-fired, 39 percent oil or gas-fired and 11 percent under purchased power contracts, with plants located in South Dakota and Wyoming.

We sell our output under contracts of varying length, thereby allowing us to mitigate the impact of a potential downturn in prices in the future. We sell energy and capacity under a combination of short- and long-term contracts as well as direct sales into the energy markets. As of December 31, 2003, approximately 68 percent of our unregulated generating capacity was sold under contracts greater than one year in duration. As a result of regulatory approval for a new long-term contract at our Las Vegas II plant being granted in March 2004, the percentage of our facilities under long-term contracts increased to approximately 90 percent. We sell the remainder of this capacity under short-term contracts or directly into the wholesale power markets.

How We Develop and Acquire Power Plants. We plan to actively pursue power plant acquisitions and development opportunities in areas we view as attractive throughout North America. Our primary focus has been, and is likely to remain, in the North American Electric Reliability Council region known as the Western Electricity Coordinating Council, or "WECC." Among the factors we consider critical in evaluating the relative attractiveness of new generation opportunities are the following:

- potential electric demand growth in the targeted region;
- regional generation capacity characteristics;
- permitting and siting requirements;
- proximity of the proposed site to high transmission capacity corridors;
- fuel supply reliability and pricing;

- the local regulatory environment; and
- the potential to exploit market expertise and operating efficiencies relating to geographic concentration of new generation with our existing power plant portfolio.

Our goal is to sell approximately 80-90 percent of the independent power generation portfolio under long-term contracts, while reserving the remainder for merchant or "spot" sales. We seek to have long-term contracts with investment grade counterparties and/or with utilities serving native loads with commission approved contracts. We aim to secure long-term power sales contracts in conjunction with project financing. This structure limits our liability and establishes a debt repayment schedule to closely match the term of the power sales contracts so that at the end of the contract term, the project debt will largely be repaid.

Rocky Mountain and West Coast Facilities. We have approximately 935 megawatts of generating capacity in the WECC states of Colorado, Nevada, Wyoming and California, as follows:

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
In Operation:						
Fountain Valley	Gas	CO	240.0	100%	240.0	2001
Arapahoe Unit 5 and 6	Gas	CO	80.0	100%	80.0	2000
Arapahoe CC5 Expansion	Gas	CO	50.0	100%	50.0	2002
Valmont Unit 7	Gas	CO	40.0	100%	40.0	2000
Valmont Unit 8	Gas	CO	40.0	100%	40.0	2001
Las Vegas I	Gas	NV	53.0	50%	26.5	1994
Las Vegas II	Gas	NV	224.0	100%	224.0	2002
Gillette CT	Gas	WY	40.0	100%	40.0	2001
Wygen	Coal	WY	90.0	100%	90.0	2003
Ontario	Gas	CA	12.0	50%	6.0	1984
Harbor	Gas	CA	80.0	100%	80.0	1989
Harbor Expansion	Gas	CA	18.0	100%	18.0	2001
Total WECC			967.0		934.5	

Fountain Valley, Arapahoe and Valmont Facilities. Our Fountain Valley, Arapahoe and Valmont plants are wholly owned gas-fired peaking facilities in the Front Range of Colorado, with a total capacity of 450 megawatts. We sell all of the output from these plants to Public Service Company of Colorado (PSCO) under tolling contracts expiring in 2012.

Las Vegas Cogeneration Facilities. Las Vegas I is a 53 megawatt, gas-fired plant northeast of Las Vegas, Nevada. Most of the power from this plant is sold to Nevada Power under a long-term contract that expires in 2024. While we own 50 percent of this plant, under accounting principles generally accepted in the United States, we consolidate 100 percent of the plant in our financial statements.

Las Vegas II is a 224 megawatt, combined-cycle, gas-fired plant that became operational early in 2003. We initially sold the power generated by Las Vegas II under a long-term contract with Allegheny Energy Supply L.L.C. On August 20, 2003, we entered into a termination agreement with Allegheny under which Allegheny agreed to pay us to terminate the long-term contract. On September 22, 2003, the termination was effective and Allegheny made the termination payment. In December 2003, we executed a new 10-year tolling agreement with Nevada Power for the capacity and power from this plant. The new contract was subject to regulatory approval, which was received in March 2004 and sales under the contract will commence April 1, 2004. We own 100 percent of Las Vegas II.

Gillette CT. The Gillette CT, a gas-fired combustion turbine located at the same site as the Wygen plant, has a total capacity of 40 megawatts and became operational in May 2001. We have a 10-year power purchase agreement in place with Cheyenne Light, Fuel and Power (CLF&P) under which we sell the energy and capacity from this facility. We assume fuel price risks under this agreement since the fuel price is fixed at the outset of each month and CLF&P has the right to dispatch the facility on a day-ahead basis. We are permitted to remarket the energy that is not prescheduled by CLF&P. This agreement has been temporarily assigned from CLF&P to its affiliate PSCO for the four-year term of CLF&P's all-requirements power purchase agreement with PSCO, which expires December 31, 2007.

Wygen Plant. The Wygen plant is a leased mine-mouth, coal-fired plant with a total capacity of 90 megawatts, which commenced operations in the first quarter of 2003. We have contracts to sell 60 megawatts of unit contingent capacity and energy from this plant to CLF&P with a term of 10 years and 20 megawatts of unit contingent capacity and energy to the Municipal Energy Agency of Nebraska (MEAN) for a term of 10 years. We have consented, subject to receipt of lender approval, to CLF&P's assignment of this agreement to its affiliate, PSCO, for the term of its all-requirements power purchase agreement, which expires December 31, 2007.

Ontario Cogeneration Facility. Ontario Cogeneration Company is a 12 megawatt, gas-fired power plant in Ontario, California, which we currently operate as a baseload plant. Electrical output from the plant is subject to a 25-year power purchase agreement with Southern California Edison, which expires in January 2010. The project also sells steam production to Sunkist Growers, Inc. under a five-year agreement, which terminates in November 2007.

Harbor Cogeneration Facility. Harbor Cogeneration, a 98 megawatt gas-fired plant located in Wilmington, California, is currently being operated as a peaking plant selling ancillary services and energy into the California Independent System Operator, or "CAISO," market. Under a settlement agreement with Southern California Edison, Harbor Cogeneration receives payments pursuant to a termination payment schedule for a period ending on October 1, 2008. We sell the peaking capacity under a tolling agreement for the summer periods through 2007. We plan to sell the remaining capacity and energy from this plant in the California market on a merchant basis.

Northeast Facilities. During 2003, we decided to exit the Eastern market and divest our assets in that region. In September 2003, we completed the sale of our ownership interests in seven hydroelectric plants in New York. These plants had a combined nameplate capacity of approximately 80 megawatts. In addition, we announced our intention to sell our 40 megawatt gas-fired plant located in Pepperell, Massachusetts.

Power Funds. In addition to our ownership of the power plants described above, we hold various indirect interests in power plants through our investment in energy and energy-related funds, both domestic and international, with a total net capacity of approximately 28 megawatts.

Fund Name	Number of Plants	Total Capacity (MWs)	Interest	Net Capacity (MWs)
Energy Investors Fund I	2	58.3	12.6%	7.4
Energy Investors Fund II	5	66.6	6.9%	4.6
Project Finance Fund III	8	256.5	5.3%	13.6
Caribbean Basin	2	60.3	3.7%	2.2
Total Fund Interests		441.7		27.8

Natural Gas and Crude Oil Production

Our oil and gas segment is involved in the acquisition, exploration, development and production of natural gas and oil resources. We hold interests in oil and gas properties located in Alabama, California, Colorado, Louisiana, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. We operate approximately 514 oil and gas wells and also own a working interest in, but do not operate, an additional 509 wells. We also own a 44.7 percent interest in the Newcastle gas processing plant located in Weston County, Wyoming adjacent to certain of our producing properties in that area.

The majority of our reserves are located in the Rocky Mountain region. Approximately 64 percent of our reserves are located in the San Juan Basin of Northwestern New Mexico, primarily in the East Blanco Field of Rio Arriba County and 24 percent are located in the Powder River Basin of Wyoming, primarily in the Finn-Shurley Field area of Weston and Niobrara counties. As of December 31, 2003, natural gas and oil comprise 79 percent and 21 percent of our total reserves, respectively. At December 31, 2003 we had total reserves of approximately 156.4 BCFE.

Summary Oil and Gas Reserve Data

The following table sets forth summary information concerning our estimated proved oil and gas reserves as of December 31, 2003, based on a report prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. Reserves were determined using year-end product prices, held constant for the life of the properties. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results.

	December 31, 2003
Proved Reserves:	
Natural gas (MMcf)	124,062
Oil (MBbl)	5,389
Total (MMcfe)	156,399
Proved Developed Reserves:	
Natural gas (MMcf)	66,294
Oil (MBbl)	4,830
Total (MMcfe)	95,274

Drilling Activity

The following table reflects our drilling activities for the year ended December 31, 2003.

Gross Wells			Net Wells		
Productive	Dry	Total	Productive	Dry	Total
67	15	82	17.14	5.38	22.52

Recompletion Activity

The following table reflects our recompletion activities for the year ended December 31, 2003.

Gross Wells			Net Wells		
Productive	Dry	Total	Productive	Dry	Total
39	3	42	31.13	1.51	32.64

Productive Wells

The following table summarizes our gross and net interests in productive wells at December 31, 2003. Net interests represented in the table are net “working interests” which bear the cost of operations.

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
New Mexico	3	162	165	2.29	153.56	155.85
Wyoming	419	98	517	269.24	16.62	285.86
Other States	16	242	258	4.86	66.26	71.12
Total	438	502	940	276.39	236.44	512.83

Acreage

The following table summarizes our undeveloped acreage by region as of December 31, 2003.

	Undeveloped	
Area	Gross	Net
Rocky Mountain Region	768,828	283,197
Other	67,636	9,843
Total	836,464	293,040

Coal Mining

Our coal production segment mines and processes low-sulfur sub-bituminous coal near Gillette, Wyoming. The Wyodak mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin, one of the largest coal reserves in the United States. We produced approximately 4.8 million tons of coal in 2003. Mining rights to the coal are based on four federal leases and one state lease. We pay royalties of 12.5 percent and 9.0 percent, respectively, of the selling price on all federal and state coal. As of December 31, 2003, we had coal reserves of 262.7 million tons, enough to satisfy present contracts for approximately 55 years. Substantially all of our coal production is currently sold under long-term contracts to: our electric utility, Black Hills Power, Inc.; PacifiCorp, which owns 80 percent of the Wyodak power plant and in which our utility owns the remaining 20 percent; and to our mine-mouth Wygen power plant. We also expect to increase our coal production to supply:

- additional mine-mouth generating capacity of up to 500 megawatts at the same site as the Wygen plant, which is in the early stages of development; and
- future sales of coal to regional rail-served customers.

Our coal segment’s agreement with Black Hills Power limits earnings from all coal sales to Black Hills Power to a specified return on our original cost-depreciated investment base. Black Hills Power made a commitment to the South Dakota Public Utilities Commission, the Wyoming Public Service Commission and the City of Gillette that coal would be furnished and priced as provided by that agreement for the life of our Neil Simpson II plant.

The price for unprocessed coal sold to PacifiCorp for its 80 percent interest in the Wyodak plant is determined by a coal supply agreement terminating in 2022.

Energy Marketing and Transportation

We market natural gas and crude oil in specific regions of the United States and Canada. We offer physical and financial wholesale energy marketing and price risk management products and services to a variety of customers. These customers include natural gas distribution companies, municipalities, industrial users, oil and gas producers, electric utilities, energy marketers and retail gas users. Our average daily marketing volumes for the year ended December 31, 2003 were approximately 1.2 million MMBtu, or British thermal units of gas and 58,700 barrels of oil.

The following table briefly summarizes the location of our fuel marketing operations and sales offices:

Company	Fuel	Marketing Operations	Sales Offices
Enserco Energy	Natural Gas	Golden, CO	Calgary, Alberta, Canada
Black Hills Energy Resources	Crude Oil	Houston, TX	Tulsa, OK; Midland, TX; Longview, TX

Our natural gas marketing operations are headquartered in Golden, Colorado, with a satellite office in Calgary, Alberta, Canada. We focus primarily on marketing of natural gas to wholesale end users and on producer marketing services. Producer marketing services include purchases of wellhead gas and risk transfer and hedging products for gas producers in the Rocky Mountain region. Our gas marketing efforts are concentrated in the Rocky Mountain, Western and Mid-continent regions of the United States and in Western Canada. We contractually hold natural gas storage capacity and both long- and short-term transportation capacity on several major pipelines in the Western and Mid-continent regions of the United States and Canada. We utilize this capacity to move relatively low cost natural gas from the producer regions to more expensive end-use market areas.

Our crude oil marketing and transportation operations are headquartered in Houston, Texas and are concentrated primarily in Texas, Oklahoma and Louisiana. Our crude oil marketing business specializes in providing independent crude oil producers with marketing and transportation services to market their crude oil production to end-use markets. In addition, we own and operate the Millennium Pipeline, a 200-mile pipeline which has a capacity of approximately 65,000 barrels of oil per day and transports imported crude oil from Beaumont, Texas to Longview, Texas, a transfer point to connecting carriers. We also own Millennium Terminal Company, L.P., which leases 1.1 million barrels of crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont.

We own and operate the 190-mile Kilgore Pipeline System. The Kilgore Pipeline System has a capacity of up to 35,000 barrels per day and transports crude oil from the Kilgore, Texas region south to Houston, Texas, which is a transport point to connecting carriers. In addition, the system has approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas.

Electric Utility

Our electric utility, Black Hills Power, is engaged in the generation, transmission and distribution of electricity. It provides a solid foundation of revenues, earnings and cash flow that support our capital expenditures, dividends, and overall performance and growth.

Distribution and Transmission

Our electric utility distribution and transmission businesses serve approximately 61,000 electric customers, with an electric transmission system of 447 miles of high voltage lines and 513 miles of lower voltage lines. In addition, we jointly own 43 miles of high voltage lines with Basin Electric Cooperative. Our utility's service territory covers a 9,300 square mile area of Western South Dakota, Eastern Wyoming and Southeastern Montana with a strong and stable economic base. Over 90 percent of our utility's retail electric revenues in 2003 were generated in South Dakota.

The following are characteristics of our distribution and transmission businesses:

- We have a diverse customer and revenue base. Our revenue mix for the year ended December 31, 2003 was comprised of 30 percent commercial, 23 percent residential, 16 percent contract wholesale, 18 percent wholesale off-system, 12 percent industrial and 1 percent municipal sales and other revenue. Approximately 74 percent of our large commercial and industrial customers are provided service under long-term contracts. We have historically optimized the utilization of our power supply resources by selling wholesale power to other utilities and to power marketers in the spot market and through short-term sales contracts.

- In 1999, the South Dakota Public Utilities Commission extended our previous retail rate freeze until January 1, 2005. The rate freeze preserves our low-cost rate structure for our retail customers at levels below the national average while allowing us to retain the benefits from cost savings and from wholesale "off-system" sales, which are not covered by the rate freeze. This provides us with flexibility in allocating our generating capacity to maximize returns in changing market environments.

- 18 percent of our electric revenues for the year ended December 31, 2003 consisted of off-system and short-term contract wholesale sales.

- Black Hills Power and Basin Electric Power Cooperative completed the construction of a jointly owned AC-DC-AC transmission tie (the transmission tie) in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts from East to West, of which we own 35 percent. This interconnection allows us to buy and sell energy in both markets without having to isolate and physically reconnect load or generation between the two electrical transmission grids. The transmission tie is bidirectional and thus accommodates scheduling transactions in both directions simultaneously. This transfer capability provides additional opportunity to sell our excess generation or to make economic purchases to serve our native load, contract obligations, and to take advantage of the power price differentials between the two electric grids. Additionally, our system is capable of directly interconnecting up to 80 megawatts of generation or load to either the Eastern or Western transmission grids. The available transmission capacity of the MAPP transmission system determines how much capacity may be directly interconnected to the Eastern system.

- We have firm point-to-point transmission access to deliver up to 17 megawatts of power on PacifiCorp's system to wholesale customers in the Western region during 2004 through 2006 and 50 megawatts during 2007 through 2023.

- We have firm network transmission access to deliver 36 megawatts of power on PacifiCorp's system to Sheridan, Wyoming to serve our contract with Montana-Dakota Utilities Company through 2006.

Power Sales Agreements

We sell approximately 47 percent of our utility's current load under long-term contracts. Our key contracts include a contract with Montana-Dakota Utilities Company, expiring in 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory, and a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are integrated into our control area and are treated as firm native load. In May 2001, we began selling 30 megawatts of firm capacity and energy to PSCO for a period through 2004. For the 10-year period beginning in 2003, our utility and our power generation segment each provide 20 megawatts of unit contingent energy and capacity to the Municipal Energy Agency of Nebraska.

Regulated Power Plants and Purchased Power

Our utility's electric load is served by coal-, oil- and natural gas-fired generating units providing 435 megawatts of generating capacity all of which is located in South Dakota and Wyoming, and from the following purchased power and capacity contracts with PacifiCorp:

- a power sales agreement expiring in 2023, involving the purchase by us of 50 megawatts of baseload power; and
- a reserve capacity integration agreement expiring in 2012, which makes available to us 100 megawatts of reserve capacity in connection with the utilization of the Ben French CT units.

Since 1995, our utility has been a net producer of energy. Our utility reached its peak system load of 392 megawatts in August 2001. None of our generation is restricted by hours of operation, thereby providing us with the ability to generate power to meet demand whenever necessary and feasible.

The following table describes our utility's portfolio of power plants:

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Ben French	Coal	SD	25.0	100%	25.0	1960
Ben French Diesels 1-5	Diesel	SD	10.0	100%	10.0	1965
Ben French CTs 1-4	Gas/Oil	SD	100.0	100%	100.0	1977-1979
Lange CT	Gas	SD	40.0	100%	40.0	2002
Neil Simpson I	Coal	WY	21.8	100%	21.8	1969
Neil Simpson II	Coal	WY	91.0	100%	91.0	1995
Neil Simpson CT	Gas	WY	40.0	100%	40.0	2000
Osage	Coal	WY	34.5	100%	34.5	1948-1952
Wyodak	Coal	WY	362.0	20%	72.4	1978
Total			724.3		434.7	

Ben French. Ben French is a wholly owned coal-fired plant located in Rapid City, South Dakota, with a capacity of 25 megawatts. This plant was put into service in 1960 and has since been operating as a baseload plant. The plant purchases coal from our Wyodak mine, which is delivered by truck.

Ben French Diesel Units 1-5. The Ben French Diesel Units 1-5 are wholly owned diesel-fired plants located in Rapid City, South Dakota, with an aggregate capacity of 10 megawatts. These plants were placed into service in 1965, and are being operated as peaking plants.

Ben French CT's 1-4. The Ben French Combustion Turbines 1-4 are wholly owned gas- and oil-fired units with a capacity of 100 megawatts located in Rapid City, South Dakota. These facilities were placed into service from 1977 to 1979, and operate as peaking units.

Lange CT. The Lange Combustion Turbine is a wholly owned 40 megawatt gas-fired plant located near Rapid City, South Dakota. The plant was placed into service in 2002 and provides peaking capacity and voltage support for the area.

Neil Simpson I and II. Neil Simpson I and II are wholly owned, air-cooled, coal-fired facilities located near Gillette, Wyoming. Neil Simpson I has a capacity of 21.8 megawatts and was placed into service in 1969. Neil Simpson II has a capacity of 91 megawatts and was placed into service in 1995. These plants operate as baseload facilities, and are mine-mouth coal-fired plants, receiving their coal directly from our Wyodak mine.

Neil Simpson CT. The Neil Simpson Combustion Turbine is a wholly owned gas-fired plant located near Gillette, Wyoming with a capacity of 40 megawatts. This plant was placed into service in 2000, and provides peaking capabilities.

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

Wyodak. Wyodak is a 362 megawatt mine mouth coal-fired plant owned jointly by PacifiCorp and us and in which we hold a 20 percent (72.4 net megawatt) ownership interest. Our Wyodak mine furnishes all the coal fuel supply for the Wyodak plant. The plant was placed into service in 1978, and operates as a baseload plant.

Communications

Our communications group, which primarily operates through our subsidiary, Black Hills FiberCom, was formed to provide state-of-the-art broadband telecommunications services to the markets of Rapid City and the Northern Black Hills of South Dakota. We offer residential and business customers a full suite of telecommunications services, including local and long distance telephone service, expanded cable television service, cable modem Internet access and high speed data and video services. We have completed a 245-mile inter- and intra-city fiber optic network and currently operate 840 miles of two-way interactive hybrid fiber coaxial or "HFC" cable. We bundle these services into value packages with a single consolidated bill for all of these services. In the future we expect to integrate electricity into the package if deregulation occurs.

We introduced our broadband communications services to the Rapid City and Northern Black Hills areas in November 1999. As of December 31, 2003, we were serving 23,878 residential customers and 3,012 business customers.

The construction of our initial infrastructure build-out, which covers Rapid City and the Northern Black Hills region, was completed in 2002. Our current emphasis is focused on achieving operating efficiencies, both internal to our communications group and those that can be realized by integrating appropriate business functions with related utility operations.

Competition

The independent power, fuel production and energy marketing industries are characterized by numerous strong and capable competitors, some of which may have more extensive operating experience, larger staffs or greater financial resources than us.

FERC has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses, and deregulation initiatives in a number of states may encourage further disaggregation. However, the pace of restructuring slowed significantly following public and governmental reactions to issues associated with deregulation efforts in California and the collapse of its wholesale electric energy market.

In addition, Congress is considering various legislative proposals to restructure the electric industry that would require, among other things, customer choice and/or repeal of the Public Utility Holding Company Act of 1935, or PUHCA. The debate is likely to continue and perhaps intensify. The effect of enacting such legislation cannot be predicted with any degree of certainty. As a result of these potential regulatory changes, significant additional competitors could become active in the generation segment of our industry.

Our communications unit faces strong competition from several companies, including Qwest Corporation, Rapid City's incumbent local exchange carrier and Midcontinent Communications, the area's incumbent cable television provider, as well as long distance providers and Internet service providers. Our success in this business will depend upon, among other things, the quality of our customer service, the willingness of residential and business customers to accept us as an alternative provider of broadband communications products and services and our ability to offer an attractive package of bundled products.

Risk Management

Our business operations require effective management of price, counterparty performance and operational risks. Price risk arises from the volatility of energy prices. Counterparty performance risk is the risk that a counterparty will fail to satisfy its contractual obligations to us, and includes credit risk. Operational risk is the risk that we will be unable to perform on our contractual obligations to our counterparties. We have implemented controls to mitigate each of these risks.

Our energy marketing operations are conducted in accordance with guidelines established through separate risk management policies and procedures for each marketing company and through our credit policy and procedures. These policies and procedures specify maximum price risk exposure levels within which each respective marketing company must operate. They establish relatively low exposure levels and strictly limit speculative trading strategies. These policies are established and approved by our board of directors, reviewed on a regular basis and monitored as described below.

We maintain a working risk management committee that oversees each of our marketing companies, and a credit committee at the parent company level. The risk management committee focuses on implementation of risk management procedures and on monitoring compliance with established policies. The credit committee monitors credit exposure levels and reviews compliance with established credit policies. Our Senior Vice President-Risk is responsible for overseeing these functions.

We further limit the exposure of our parent holding company, Black Hills Corporation, to energy marketing risks by maintaining separate credit facilities within each of our energy marketing companies. These credit facilities have security interests solely against the assets of the relative marketing company. In addition, we limit the number and amount of any parent guarantees for the marketing companies.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. Short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risks, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities exceed our anticipated load requirements plus a required reserve margin.

Regulation

We are subject to a broad range of federal, state and local energy and environmental laws and regulations applicable to the development, ownership and operation of our projects. These laws and regulations generally require that a wide variety of permits and other approvals be obtained before construction or operation of a project commences and that, after completion, the facility operate in compliance with such requirements. We strive to comply with the terms of all such laws, regulations, permits and licenses and believe that all of our operating facilities are in material compliance with all such applicable requirements.

Energy Regulation

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 are required to file rate schedules with FERC prior to commencement of wholesale sales or interstate transmission of electricity. Public utilities with cost-based rate schedules are also subject to accounting, record-keeping and reporting requirements administered by FERC.

The Energy Policy Act. The passage of the Energy Policy Act in 1992 further encouraged independent power production by providing certain exemptions from regulation for exempt wholesale generators, or EWGs. An EWG is an entity that is directly or indirectly, in the business of owning or operating facilities that are exclusively engaged in generation and selling electric energy at wholesale. An EWG will not be regulated under PUHCA, but is subject to FERC and state public utility commission regulatory reviews, including rate approval. Since EWGs are only allowed to sell power at wholesale, their rates must receive initial approval from FERC rather than from the state regulators. All of our subsidiaries that would otherwise be treated as public utilities are currently treated as EWGs under the Energy Policy Act or as Qualifying Facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). All of our EWGs have been granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates. However, FERC customarily reserves the right to suspend, upon complaint, market-based rate authority on a prospective basis if it is subsequently determined that we or any of our EWGs exercised market power. If FERC were to suspend market-based rate authority, we would most likely be required to file, and obtain FERC acceptance of, cost-based rate schedules for our affected EWGs. Also, the loss of market-based rate authority would subject the EWGs to the accounting, record keeping and reporting requirements that are imposed on public utilities with cost-based rate schedules.

In addition, if there occurs a "material change" in facts that might affect any of our subsidiaries' eligibility for EWG status, within 60 days of the material change, the relevant EWG must (1) file a written explanation of why the material change does not affect its EWG status, (2) file a new application for EWG status, or (3) notify FERC that it no longer wishes to maintain EWG status. If any of our subsidiaries were to lose EWG status, we, along with our affiliates, would be subject to regulation under PUHCA as a public utility company.

PURPA. The enactment of PURPA in 1978 provided incentives for the development of QFs which were basically cogeneration facilities and small power production facilities that utilized certain alternative or renewable fuels. QF status conveys two primary benefits. First, regulations under PURPA exempt QFs from PUHCA, most provisions of the Federal Power Act and the state laws concerning rates, and financial and organizational regulations of electric utilities. Second, FERC's regulations under PURPA require that (1) electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's full avoided cost of producing power, (2) the electric utilities must sell back-up, interruptible, maintenance and supplemental power to the QF on a non-discriminatory basis, and (3) the electric utilities must interconnect with any QF in its service territory, and, if required, transmit power if they do not purchase it. We endeavor to acquire, develop and operate our QFs in a manner that minimizes the risk of those plants losing their QF status. However, if a facility were to lose QF status, we could attempt to avoid regulation under PUHCA by qualifying the project as an EWG.

Public Utility Holding Company Act of 1935. We are an exempt holding company under the 1935 Act. By virtue of the expansion of our business outside of the State of South Dakota, including non-utility business activities, we may be required to become a registered holding company under the 1935 Act. In that event, the 1935 Act and related regulations issued by the SEC would govern our activities and activities of our subsidiaries with respect to the acquisition and sale of securities, acquisition and sale of utility assets, certain transactions among affiliates, engaging in business activities not directly related to the utility or energy business and other matters. Over the past few years, several bills have been introduced in Congress to repeal the 1935 Act, and repeal provisions are currently again pending before Congress. However, it remains uncertain whether any such legislation will be enacted.

State Energy Regulation. In areas outside of wholesale rate regulation (such as financial or organizational regulation), some state utility laws may give their public utility commissions broad jurisdiction over steam sales or EWGs that sell power in their service territories. The actual scope of the jurisdiction over steam or independent power projects depends on state law and varies significantly from state to state.

Environmental Regulation

The construction and operation of power projects, coal mines, oil and gas exploration/production and crude oil handling facilities 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. If such laws and regulations are changed and our facilities are not grandfathered, extensive modifications to project technologies and facilities could be required.

General. Based on current trends, we expect that environmental and land use regulation will continue to be stringent. Accordingly, we actively review proposed construction projects that could subject us to stringent pollution controls imposed on "major modifications," as defined under the Clean Air Act, and changes in "discharge characteristics," as defined under the Clean Water Act. The goal of these actions is to achieve compliance with applicable regulations, administrative consent orders and variances from applicable air-quality related regulations.

Air Quality. Our Neil Simpson II, Neil Simpson CT, Gillette CT, Wygen, Arapahoe, Valmont, Fountain Valley, Las Vegas II, Lange CT and Wyodak plants are all subject to Title IV of the Clean Air Act, which requires certain fossil-fuel-fired combustion devices to hold sulfur dioxide "allowances" for each ton of sulfur dioxide emitted. We currently hold sufficient allowances credited to us as a result of sulfur removal equipment previously installed at the Wyodak plant to apply to the operation of all units subject to Title IV through 2032 without requiring the purchase of any additional allowances. With respect to any future plants, we plan to comply with the need for holding the appropriate number of allowances by reducing sulfur dioxide emissions through the use of low sulfur fuels, installation of "back end" control technology and if necessary, the purchase of allowances on the open market. We expect to integrate the costs of obtaining the required number of allowances needed for future projects into our overall financial analysis of such projects.

In July 1999, the United States Environmental Protection Agency (EPA) finalized rules designed to protect and improve visibility impairment resulting from air emissions. Among other things, the regulations required states to identify sources of emissions (including certain coal-fired generating units built between 1962 and 1977) by 2004 that would be subject to "Best Available Retrofit Technology," known as BART. These sources would be required to implement BART within five years after the EPA approves state plans adopted to combat visibility impairment. Subsequent litigation has removed EPA's requirement mandating that states adopt and impose BART requirements; however, it remains an option for states to use in addressing visibility impairment. Management believes the only existing plant which may be required to comply with the BART requirements is our Neil Simpson I plant in Wyoming. Late in 2003, the State of Wyoming adopted an emissions trading program as their visibility impairment plan and that plan is currently under review for approval by the EPA. After discussions with state staff, we believe this program will not have a material adverse effect on our financial position or results of operations. We are aware that other states in which we have power plants, are required to submit their visibility impairment plans to EPA between 2004 and 2008 and that compliance is due within five years of EPA approval. Management believes that any capital expenditures associated with future compliance requirements would not have a material adverse effect on our financial position or results of operations.

Title V of the Clean Air Act imposes federal requirements, which dictate that all of our fossil fuel-fired generation facilities must obtain operating permits. All of our existing facilities subject to this requirement have submitted Title V permit applications and either have received or are in the process of receiving permits.

On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act's "new source review" (NSR) requirements related to modifications of air emissions sources at electric generating stations located in the Southern and Midwestern regions of the United States. Several states joined these lawsuits. In addition, the EPA has also issued administrative notices of violation alleging similar violations at additional power plants owned by some of the same utilities named as defendants in the Department of Justice lawsuit. The EPA has also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities seeking to determine whether those utilities also engaged in activities that may have been in violation of the Clean Air Act's NSR requirements. In May 2003, EPA notified PacifiCorp that it is investigating similar activities at their Wyodak Plant, in which we hold a 20 percent ownership interest. We are receiving copies of all information provided to EPA. At this time no legal proceedings have commenced. No such NSR proceedings have been initiated or requests for information issued with respect to any of our other facilities, but we cannot assure you that we will not be subject to similar proceedings in the future.

In December 2000, the EPA announced its intention to regulate mercury emissions from coal and oil-fired electric power plants. In December 2003 EPA issued the proposed rules and solicited comments on regulatory options for regulating mercury. At this time, we are not able to fully evaluate the impact of potential mercury regulations on the operation of our facilities.

Since the adoption of the United Nations Framework on Climate Change in 1992, there has been worldwide attention with respect to greenhouse gas emissions, in particular carbon dioxide. In December 1997, the Clinton administration participated in the Kyoto, Japan negotiations, where the basis of a climate change treaty was formulated. Under the treaty, known as the Kyoto Protocol, the United States would be required, between 2008 and 2012 to reduce its greenhouse gas emissions by 7 percent from 1990 levels. The treaty has never been ratified by the United States, although discussions continue regarding climate change issues. Although legislative developments on the state level related to controlling greenhouse gas emissions have occurred, we are not aware of any similar developments in the states in which we operate. If we should become subject to limitations on emissions of carbon dioxide from our power plants, these requirements could have a significant impact on our operations.

Clean Water Act. Our existing facilities are also subject to a variety of state and federal regulations governing existing and potential water/wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under authority of the Clean Water Act and govern overall water/wastewater discharges through National Pollutant Discharge Elimination System, or NPDES, permits. Under current provisions of the Clean Water Act, existing NPDES permits must be renewed every five years, at which time permit limits are extensively reviewed and can be modified to account for changes in regulations or program initiatives. In addition, the permits have re-opener clauses which allow the permitting authority (which may be the United States or an authorized state) to attempt to modify a permit to conform to changes in applicable laws and regulations. Some of our existing facilities have been operating under NPDES permits for many years and have gone through one or more NPDES permit renewal cycles. All of our facilities required to have NPDES permits have those permits in place and are in compliance with discharge limitations. There are no proposed regulations that we are aware of that will have a significant impact on our operations. Our Harbor Cogeneration facility will be incurring a capital expense of approximately $1.0 million to re-route plant wastewater to the municipal sewer system. Additionally, EPA regulates surface water oil pollution prevention through their oil pollution prevention regulations. All facilities regulated under this program have their required plans in place.

Solid Waste Disposal. We dispose of all solid wastes collected as a result of burning coal at our power plants in approved solid waste disposal sites. Each disposal site has been permitted by the state of its location in compliance with law. Ash and wastes from flue gas and sulfur removal from the Wyodak, Wygen, Neil Simpson I, Ben French and Neil Simpson II plants are deposited in mined areas. These disposal areas are located below some shallow water aquifers in the mine. None of the solid wastes from the burning of coal is classified as hazardous material, but the wastes do contain minute traces of metals that would be perceived as polluting if such metals leached into underground water. Recent investigations have concluded that the wastes are relatively insoluble and will not measurably affect the post-mining ground water quality. While management does not believe that any substances from our solid waste disposal activities will pollute underground water, we cannot assure you that no pollution will occur over time. In this event, we could experience material costs to mitigate any resulting damages. Agreements in place require PacifiCorp to be responsible for any such costs that would be related to the solid waste from its 80 percent interest in the Wyodak plant.

Additional unexpected material costs could also result in the future if any regulator determines that solid waste from the burning of coal contains some hazardous material that requires special treatment, including solid waste of which we previously disposed. In that event, the government regulator could consequently hold those entities that disposed of such waste responsible for such treatment.

Pipeline Operations. The operations of pipelines and other facilities for gathering, transporting, processing or storing natural gas and crude oil is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with federal, state and local laws that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. Costs of constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws, regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures.

Mine Reclamation. Under federal and state laws and regulations, we are required to submit to the regulation by, and receive approval from, the Wyoming Department of Environmental Quality (DEQ) for a mining and reclamation plan which provides for orderly mining, reclamation and restoration of our entire Wyodak coal mine in conformity with state laws and regulations. We have an approved mining permit and are otherwise in compliance with other permitting programs administered by various regulatory agencies.

Based on extensive reclamation studies, we have accrued approximately $15.8 million on our accompanying Consolidated Balance Sheets for these reclamation costs. No assurance can be given that additional requirements in the future will not be imposed that would cause an unexpected material increase in reclamation costs.

One situation that could result in substantial unexpected increases in costs relating to our reclamation permit concerns three depressions -- the "South" depression, the "Peerless" depression and the "Clovis Pit" depression - that have or will result from our mining activities at the Wyodak mine. Because of the thick coal seam and relatively shallow overburden, the current restoration plan would leave these depressions, which have limited reclamation potential, with interior drainage only. Although the DEQ has accepted the current plan to limit reclamation of these depressions, it has reserved the right to review and evaluate future reclamation plans or to reevaluate the existing reclamation plan. If as a result of our mining activities, additional overburden becomes available, the DEQ may require us to conduct additional reclamation of the depressions, particularly if the DEQ finds that the current limited reclamation is resulting in exceedances in the DEQ's water quality standards.

Ben French Oil Spill. In 1990 and 1991, we discovered extensive underground fuel oil contamination at the Ben French plant site. With the help of expert consultants, we worked closely with the South Dakota Department of Environment and Natural Resources to assess and remediate the site. Our assessment, remediation and site monitoring efforts continue today. All of our underground oil-carrying facilities from which the contamination occurred are now above ground. There have been no significant recoveries of free fuel oil product since 1994. Soil borings and monitoring wells on the perimeters of our Ben French plant property provide no indication of contamination beyond the property's limits. Management believes that the underground spill has been sufficiently remedied so as to prevent any oil from migrating off site. However, due to underground gypsum deposits in this area, the fuel oil has the potential of migrating to area waterways. In such event, cleanup costs could be greatly increased. Management believes that sufficient remediation efforts to prevent such a migration are currently in place, but due to the uncertainties of underground geology, we cannot assure you that no such migration will occur.

Cleanup costs recognized to date total approximately $0.5 million, of which amount $0.4 million has been reimbursed by the South Dakota Petroleum Release Compensation Fund. To date, no penalties, claims or actions have been taken or threatened against us because of this oil spill. In 2002, the South Dakota Department of Environment and Natural Resources permanently closed numerous monitoring wells which showed no contamination for several years.

PCBs. Under the federal Toxic Substances Control Act, the EPA has issued regulations that control the use and disposal of polychlorinated biphenyls, or PCBs. PCBs were widely used as insulating fluids in many electric utility transformers and capacitors manufactured before the Toxic Substances Control Act prohibited any further manufacture of PCB equipment. We remove and dispose of PCB-contaminated equipment in compliance with law as it is discovered.

Release of PCB-contaminated fluids, especially any involving a fire or a release into a waterway, could result in substantial cleanup costs. Several years ago, we began a testing program of potential PCB-contaminated transformers, and in 1997 completed testing of all transformers and capacitors which are not located in our electric substations. We have not completed the testing of sealed potential transformers and bushings located in our electric substations as the testing of this equipment requires their destruction. Release of PCB-contaminated fluid, if present, from our equipment is unlikely and the volume of fluid in such equipment is generally less than one gallon. Moreover, any release of this fluid would be confined to our substation site.

Exploration and Production

Our oil and gas exploration and production operations are subject to various types of regulation at the federal, state and local levels. They include:

- requiring permits for the drilling of wells;
- maintaining bonding requirements in order to drill or operate wells;
- submitting and implementing spill prevention plans;
- submitting notification relating to the presence, use and release of certain contaminants incidental to oil and gas operations, as required under EPA Emergency Planning and Community Right to Know Act (EPCRA) regulations;
- regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities;
- submitting air permit applications for agency review and possible issuance of operating permits;

- compliance with EPA Resource Conservation and Recovery Act (RCRA) requirements; and

- regulating surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production.

Our operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a unit and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and gas we can produce from our wells and to limit the number of wells or the locations at which we can drill. In addition, various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants and the protection of public health, natural resources, wildlife and environment affect our exploration, development and production operations and our related costs.

Other Properties

In addition to the other properties described herein, we own an eight-story office building with approximately 47,000 square feet, of which we occupy approximately 75 percent and lease the remainder to others. We also own two additional office buildings consisting of approximately 48,000 square feet and two warehouse buildings consisting of approximately 35,700 square feet. All of these properties are located in Rapid City, South Dakota.

Employees

At December 31, 2003, we had 872 employees, 294 of whom are employed in our utility business, 261 of whom are employed in our wholesale energy businesses, 242 of whom are employed in our communications business and 75 of whom are employed at the corporate level.

Approximately one-half of our utility employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers, which expires on March 31, 2006. We have experienced no labor stoppages or significant labor disputes at our facilities.

RISK FACTORS

The following specific risk factors and other risk factors that we discuss in our periodic reports from time to time should be considered for a better understanding of our Company. These factors and other matters discussed herein are important factors that could cause our actual results or outcomes to differ materially from those discussed in the forward looking statements included elsewhere in this document.

Our agreements with counterparties that have recently experienced downgrades in their credit ratings expose us to the risk of counterparty default, which could adversely affect our cash flow and profitability.

We are exposed to credit risks in our power generation, distribution and energy marketing operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. In the past two years, a substantial number of energy companies have experienced downgrades in their credit ratings, some of which serve as our counterparties from time to time. In particular, the credit ratings of the senior unsecured debt of Public Service Company of Colorado and Nevada Power Company, counterparties under tolling agreements with our subsidiaries, have been downgraded by one or more rating agencies. The credit rating of Nevada Power Company was downgraded to non-investment grade status. In addition, we have project level financing arrangements in place that provide for the potential acceleration of payment obligations in the event of nonperformance by a counterparty under related power purchase agreements. If these or other counterparties fail to perform their obligations under their respective power purchase agreements, our financial condition and results of operations may be adversely affected. We may not be able to enter into replacement power purchase agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement power purchase agreements, we would sell the plant's power at market prices.

Our credit ratings have recently been lowered and could be further lowered in the future. If this were to occur, our access to capital and our cost of capital and other costs would be negatively affected.

Our issuer credit rating was recently downgraded to Baa3 by Moody's Investor Services, Inc., or Moody's and BBB- by Standard & Poor's Rating Service. Any further reduction in our ratings by Moody's or Standard & Poor's, particularly a reduction to a level below investment-grade, could adversely affect our ability to refinance or repay our existing debt and to complete new financings on acceptable terms or at all.

In addition, a further downgrade in our credit rating would increase our costs of borrowing under some of our existing debt obligations, including borrowings made under our revolving credit facilities, our $128.3 million Wygen plant project financing, and our $25.9 million and $4.3 million secured financings.

A downgrade could also result in our business counterparties requiring us to provide additional amounts of collateral under new transactions.

We must rely on cash from our subsidiaries to make debt payments. There may be changes in the regulatory environment that restrict our utility's ability to pay dividends to us.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Consequently, our operating cash flow and our 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 contractual or regulatory restrictions that may be applicable to it, which may include requirements to maintain minimum levels of cash, working capital or debt service funds.

Our utility is regulated by utility commissions in the States of South Dakota and Wyoming. These commissions generally possess broad powers to ensure that the needs of the utility customers are being met and that we maintain a reasonable capital structure. As a result of the energy crisis in California and the financial troubles at a number of energy companies, some state utility commissions have imposed restrictions on the ability of the utilities they regulate to pay dividends or make advances to their parent holding companies. If the utility commissions in South Dakota or Wyoming choose to adopt similar restrictions, our utility's ability to pay dividends or advance funds to us would be limited, which could materially and adversely affect our ability to meet our financial obligations.

Geopolitical tensions may impair our ability to raise capital and limit our growth.

Continuing conflict in the Middle East or further tensions with the government of North Korea could disrupt capital markets and make it more costly or temporarily impossible for us to raise capital, thus hampering the implementation of our growth strategy. In the past, geopolitical events, including the uncertainty associated with the Gulf War in 1991 and the terrorist attacks of September 11, 2001, have been associated with general economic slowdowns. A prolonged conflict or stalemate arising from current geopolitical tensions or other factors could retard economic growth and reduce demand for the power and fuel products that we produce or market, which could adversely affect our earnings.

Our rate freeze agreement with the South Dakota Public Utilities Commission, which prevents us, absent extraordinary circumstances, from passing on to our South Dakota retail customers cost increases we may incur during the rate freeze period, could decrease our operating margins.

Our rate freeze agreement with the South Dakota Public Utilities Commission (SDPUC) is effective until January 1, 2005. We may not file for any increase in our rates or invoke any fuel and purchased power adjustment tariff which would take effect during the freeze period, except in extraordinary circumstances. Because we are generally unable to increase our rates, our utility's historically stable returns could be threatened by plant outages, machinery failure, increases in purchased power costs over which we have no control, acts of nature, acts of terrorism or other unexpected events that could cause our operating costs to increase and our operating margins to decline. Moreover, in the event of unexpected plant outages or machinery failures, we may be required to purchase replacement power in wholesale power markets at prices which exceed the rates we are permitted to charge our retail customers. After the rate freeze agreement expires, current rates will remain in effect until a point when the SDPUC would decide new rates are appropriate.

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

A substantial portion of our growth in net income in recent years is attributable to increasing sales of wholesale electricity and natural gas into a robust market. The prices of energy products in the wholesale power markets have stabilized at lower levels after the price volatility experienced in the second half of 2000 and the first half of 2001. Power prices are influenced by many factors outside our control, including:

- fuel prices;
- transmission constraints;
- supply and demand;
- weather;
- economic conditions; and
- the rules, regulations and actions of the system operators in those markets.

Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

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

Our broadband communications business is subject to significant competition for its services and to rapid technological change.

Our communications group, which provides a full suite of communication services, faces strong competition for its services from the incumbent local exchange carrier and from long distance providers, Internet service providers, the incumbent cable television provider and others.

Our ability to recover our capital investment is dependent on our ability to sustain our customer base and is subject to the risk that technological advances may render our network obsolete. If we determine that we will be unable to recover our investment, we would be required to take a non-cash charge to earnings in an amount that could be material in order to write down a portion of our investment in our broadband communications business.

Construction, expansion, refurbishment and operation of power generating and transmission and resource recovery facilities involve significant risks which could lead to lost revenues or increased expenses.

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

- the inability to obtain required governmental permits and approvals;
- the unavailability of equipment;
- supply interruptions;
- work stoppages;
- labor disputes;
- social unrest;
- weather interferences;
- unforeseen engineering, environmental and geological problems; and
- unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, especially in the case of newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses, 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 adequate to cover lost revenues, increased expenses or liquidated damage payments.

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

The growth of our independent power business through development, expansion and acquisition activities is critical to our future growth. We may not be able to continue to develop attractive opportunities or to complete acquisitions or development projects we undertake. Factors that could cause our activities to be unsuccessful include:

- competition;
- lower than anticipated increases in the demand for power in our target markets;
- changes in federal or state laws and regulations;
- our inability to negotiate acceptable acquisition, construction, fuel supply, power sales or other material agreements;
- our inability to obtain financing on acceptable terms, or at all;
- our inability to obtain required governmental permits and approvals;
- capital market conditions; and
- our inability to successfully integrate any businesses we acquire.

Estimates of the quantity and value of our proved 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 interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretations and judgment, and the assumptions used regarding quantities of recoverable oil and gas reserves and prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and these variances may be significant. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from our estimates. In addition, results of drilling, testing and production and changes in oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

Our business is subject to substantial governmental regulation and permitting requirements as well as on-site environmental liabilities we assumed when we acquired some of our facilities. We may be adversely affected by any future inability to comply with existing or future regulations or requirements or the potentially high cost of complying with such requirements.

Our business is subject to extensive energy, environmental and other laws and regulations of federal, state and local authorities. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to operate our facilities. In the course of complying with these requirements, we may incur significant additional costs. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. In addition, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulation may have a detrimental effect on our business.

In acquiring some of our facilities, we assumed on-site liabilities associated with the environmental condition of those facilities, regardless of when such liabilities arose and whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We strive at all times to be in compliance with all applicable environmental laws and regulations. However, steps to bring our facilities into compliance, if necessary, could be expensive, and thus could adversely affect our results of operation and financial condition. Furthermore, with the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate, we expect our environmental expenditures to be substantial in the future.

Results of an investigation into reporting of trading information could adversely affect our business.

In March 2003, we received a request for information from the Commodity Futures Trading Commission, or CFTC, calling for the production, among other things, of "all documents relating to natural gas and electricity trading" in connection with the CFTC's industry wide investigation of trade and trade reporting practices of power and natural gas trading companies. We cooperated fully with the CFTC producing documents and other materials in response to more specific requests relating to the reporting of natural gas trading information to energy industry publications, conducted our own internal investigation into the accuracy of information that former employees of Enserco Energy Inc., our gas marketing subsidiary, voluntarily reported to trade publications, and provided detailed reports of our investigation to the CFTC.

On July 31, 2003 we announced that a settlement was reached with the CFTC on this investigation, whereby we agreed to pay a civil monetary penalty of $3.0 million. Although we agreed to this civil monetary penalty with the CFTC, we cannot guarantee that other legal proceedings, civil or criminal fines or penalties, or other regulatory action related to this issue will not occur which, in turn, could adversely affect our financial condition or results of operations.

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

- consumer demands;
- technological advances;
- deregulation;
- greater availability of natural gas-fired power generation; and
- other factors.

FERC has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses, and deregulation initiatives in a number of states may encourage further disaggregation. As a result, significant additional competitors could become active in the generation, transmission and distribution segments of our industry, which could negatively affect our ability to expand our asset base.

In addition, the independent system operators who oversee most 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 types of price limitations and other mechanisms may adversely affect the profitability of those 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.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the "Legal Proceedings" subcaption within Item 8, Note 14, "Commitments and Contingencies", of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2003.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

Daniel P. Landguth, age 57, has been Chairman of the Board since January 2004. He served as Chairman of the Board and Chief Executive Officer from January 1991 to January 2004. Mr. Landguth also currently chairs the Executive Committee. He has over 30 years of experience with Black Hills. Mr. Landguth holds a B.S. degree in Electrical Engineering from the South Dakota School of Mines and Technology.

David R. Emery, age 41, was elected President, Chief Executive Officer and a member of the Board of Directors in January 2004. Prior to that, he was our President and Chief Operating Officer - Retail Business Segment from April 2003 to January 2004 and Vice President-Fuel Resources from January 1997 to April 2003. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 15 years of experience with us. He holds a B.S. in Petroleum Engineering from the University of Wyoming and a M.B.A. from the University of South Dakota.

Everett E. Hoyt, age 64, has been Chief Operating Officer since January 2004. He served as President and Chief Operating Officer from February 2001 to January 2004. From 1989 to April 2003, he was also President and Chief Operating Officer of our electric utility. Mr. Hoyt was elected to the Board of Directors in 1991. Prior to joining us, Mr. Hoyt was employed by NorthWestern Corporation for 16 years where he served as Senior Vice President-Legal and as a member of the Board of Directors. He holds a B.S. degree in Mechanical Engineering from the South Dakota School of Mines and Technology and a J.D. from the University of South Dakota School of Law.

Thomas M. Ohlmacher, age 52, has been the President and Chief Operating Officer of our Wholesale Energy Group since November 2001. He served as Senior Vice President-Power Supply and Power Marketing from January 2001 to November 2001 and Vice President - Power Supply from 1994 to 2001. Prior to that, he held several positions with our company since 1974. Mr. Ohlmacher holds a B.S. in Chemistry from the South Dakota School of Mines and Technology.

Mark T. Thies, age 40, has been our Executive Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. From 1990 to 1997, Mr. Thies served in a number of accounting positions with InterCoast Energy Company, an unregulated energy company and a wholly owned subsidiary of MidAmerican Energy Holdings Company. Mr. Thies holds a B.A. in Accounting and a B.A. in Business Administration from Saint Ambrose College and is a Certified Public Accountant.

James M. Mattern, age 49, has been the Senior Vice President - Corporate Administration and Compliance since April 2003, Senior Vice President-Corporate Administration from September 1999 to April 2003, and was Vice President-Corporate Administration from January 1994 to September 1999. From 1997 to 1999, he was also Assistant to the CEO. Mr. Mattern has 16 years of experience with us. He holds a B.S. in Social Sciences and an M.S. in Administration from Northern State University.

Steven J. Helmers, age 47, has been our Senior Vice President, General Counsel since January 2004. He served as our Senior Vice President, General Counsel and Corporate Secretary from January 2001 to January 2004. Prior to joining us, Mr. Helmers was an attorney and a shareholder with the Rapid City, South Dakota law firms of Truhe, Beardsley, Jensen, Helmers & VonWald, from 1997 to January 2001, and Lynn, Jackson, Schultz & Lebrun, P.C., from 1983 to 1997. He holds a J.D. from the University of South Dakota School of Law.

Russell L. Cohen, age 43, has been Senior Vice President and Chief Risk Officer since May 2002. Prior to joining Black Hills, Mr. Cohen was General Partner and Chief Financial Officer at Regenesis Group, LLC from December 2000 to April 2002, and was Chief Financial Officer at Worldbridge Broadband Services, Inc. from January 1998 to November 2000. Mr. Cohen holds a B.S. in Economics from Yale University and an M.B.A. from Stanford.

Maurice T. Klefeker, age 47, was elected Senior Vice President - Strategic Planning and Development in March 2004. Prior to that he served as Senior Vice President of our subsidiary, Black Hills Generation, Inc. from September 2002 to March 2004 and as Vice President of Corporate Development from July 2000 to September 2002. He joined Indeck Capital, Inc. in December 1995 as Asset Manager and later served as Vice President of Business Development until July 2000. Prior to that he served in a variety of technical and engineering positions with Northern Indiana Public Service Company for 14 years. Mr. Klefeker holds a B.S. from Purdue University and a M.B.A. from the University of Notre Dame.

Roxann R. Basham, age 42, was elected Vice President - Governance and Corporate Secretary in February 2004. Prior to that, she was our Vice President-Controller from March 2000 to January 2004. From December 1997 to March 2000, she was Vice President-Finance and Secretary/Treasurer. From 1993 until December 1997, she served as our Secretary/Treasurer, and has a total of 20 years of experience with us. She holds a B.S. in Business Administration from the University of South Dakota and is a Certified Public Accountant.

Garner M. Anderson, age 42, has been our Vice President and Treasurer since July 2003. Mr. Anderson has over 16 years of experience with us, including positions as Director - Treasury Services and Risk Manager. Mr. Anderson holds a B.S. in Accounting from the University of South Dakota and an M.B.A. in Finance from Arizona State University, and is a Certified Public Accountant.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is traded on The New York Stock Exchange under the symbol BKH. As of January 31, 2004, we had 5,667 common shareholders of record and approximately 16,000 beneficial owners, representing all 50 states, the District of Columbia and 12 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 2004 meeting, our board of directors raised the quarterly dividend to $0.31 per share, equivalent to an annual dividend of $1.24 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. Our credit facilities contain restrictions on the payment of cash dividends, the most restrictive of which prohibit the payment of cash dividends if our fixed charge coverage ratio, as calculated in our credit agreements, is less than 1.5:1.0, our recourse leverage ratio exceeds 0.65:1.00 or our consolidated net worth does not exceed the sum of $475 million and 50 percent of our aggregate consolidated net income since April 1, 2003.

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

Year ended December 31, 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Common stock prices				
High	$ 28.39	$ 31.70	$ 33.54	$ 33.15
Low	$ 21.85	$ 27.00	$ 29.82	$ 27.76

Year ended December 31, 2002	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.29	$ 0.29	$ 0.29	$ 0.29
Common stock prices				
High	$ 33.98	$ 36.90	$ 35.08	$ 27.75
Low	$ 26.01	$ 31.62	$ 23.03	$ 18.36

UNREGISTERED SECURITIES ISSUED DURING THE FOURTH QUARTER OF 2003

On November 10, 2003, we issued the following unregistered securities pursuant to the 2002 earn-out formula agreed to in the acquisition of Indeck Capital, Inc. on July 7, 2000. The unregistered securities were issued in reliance on the exemption provided by Rule 506 of Regulation D of the Securities Act of 1933. We received no additional consideration in exchange for the earnout shares.

Stockholder	Common Shares Issued	Series 2000-A Preferred Stock Issued
Gerald R. Forsythe	55,315	1,611
John W. Salyer, Jr	10,706	311
Michelle R. Fawcett	5,799	168
Marsha Fournier	5,799	168
Monica Breslow	5,799	168
Melissa S. Forsythe	5,799	168

ITEM 6. SELECTED FINANCIAL DATA

Years ended December 31,	2003	2002	2001	2000	1999
TOTAL ASSETS (in thousands)	$ 2,063,225	$ 1,999,974	$1,651,765	$1,252,936	$664,863
PROPERTY, PLANT AND EQUIPMENT (in thousands)					
Total property, plant and equipment	$ 1,882,697	$ 1,703,372	$1,378,327	$ 911,668	$699,928
Accumulated depreciation and depletion	440,275	377,568	297,400	252,816	243,311
Capital expenditures	116,691	303,918	594,142	173,517*	152,948
CAPITALIZATION (in thousands)					
Long-term debt, net of current maturities	$ 868,459	$ 540,958	$ 329,771	$ 213,606	$160,700
Preferred stock equity	8,143	5,549	5,549	4,000	--
Common stock equity	701,604	529,614	509,615	278,346	216,606
Total capitalization	$ 1,578,206	$ 1,076,121	$ 844,935	$ 495,952	$377,306
CAPITALIZATION RATIOS					
Long-term debt, net of current maturities	55.0%	50.3%	39.0%	43.1%	42.6%
Preferred stock equity	0.5	0.5	0.7	0.8	--
Common stock equity	44.5	49.2	60.3	56.1	57.4
Total	100.0%	100.0%	100.0%	100.0%	100.0%
TOTAL OPERATING REVENUES (in thousands)	$ 1,250,052**	$ 908,491	$ 737,827	$ 741,121	$546,889
INCOME FROM CONTINUING OPERATIONS BEFORE CHANGE IN ACCOUNTING PRINCIPLE (in thousands)	$ 56,995	$ 58,579	$ 84,111	$ 51,944	$ 37,738
DIVIDENDS PAID ON COMMON STOCK (in thousands)	$ 37,025	$ 31,116	$ 28,517	$ 23,527	$ 22,602
COMMON STOCK DATA (in thousands)					
Shares outstanding, average	30,496	26,803	25,374	22,118	21,445
Shares outstanding, average diluted	31,015	27,167	25,771	22,281	21,482
Shares outstanding, end of year	32,298	26,933	26,652	22,921	21,372
(in dollars)					
Basic earnings per average share -					
Continuing operations	$ 1.86	$ 2.18	$ 3.29	$ 2.35	$ 1.76
Discontinued operations	0.31	0.07	0.16	0.04	(0.03)
Change in accounting principle	(0.17)	0.03	--	--	--
Total	$ 2.00	$ 2.28	$ 3.45	$ 2.39	$ 1.73
Diluted earnings per average share -					
Continuing operations	$ 1.84	$ 2.16	$ 3.27	$ 2.33	$ 1.76
Discontinued operations	0.30	0.07	0.15	0.04	(0.03)
Change in accounting principle	(0.17)	0.03	--	--	--
Total	$ 1.97	$ 2.26	$ 3.42	$ 2.37	$ 1.73
Dividends paid per share	$ 1.20	$ 1.16	$ 1.12	$ 1.08	$ 1.04
Book value per share, end of year	$ 21.72	$ 19.66	$ 19.12	$ 12.14	$ 10.14
RETURN ON AVERAGE COMMON STOCK EQUITY (year-end)	9.9%	11.8%	22.2%	21.3%	17.5%

*Excludes the non-cash acquisition of Indeck Capital, Inc.
**Includes $114.0 million of contract termination revenue

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 a diversified energy company operating principally in the United States with three major business groups – wholesale energy, electric utility and communications. Our unregulated and regulated businesses have expanded significantly in recent years. We report for our business groups in the following financial segments:

Business Group	Financial Segment
Wholesale energy group	Power generation
	Oil and gas exploration and production
	Coal mining
	Energy marketing
Electric utility group	Electric utility
Communications group	Communications

Our wholesale energy group, Black Hills Energy, Inc., engages in the production of electric power through ownership of a diversified portfolio of generating plants and the sale of electric power and capacity primarily under long-term contracts, the production of coal, natural gas and crude oil primarily in the Rocky Mountain region, and the marketing and transportation of fuel products. Our electric utility, Black Hills Power, Inc., generates, transmits and distributes electricity to an average of approximately 61,000 customers in South Dakota, Wyoming and Montana. Our communications group provides broadband telecommunication services to approximately 26,890 residential and business customers in Rapid City and the Northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

In 2003, we made the decision to divest of our non-strategic power generation assets located in the Northeastern United States. On September 30, 2003, we sold our seven hydroelectric power plants located in Upstate New York.

In 2002, we discontinued operations of our coal marketing business due to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to East Coast markets. The non-strategic assets were sold effective August 1, 2002.

Business Strategy

We strive to operate as an integrated energy company. We participate in multiple segments of the energy value chain, which should reduce our total corporate risk and allow us to achieve higher than average market returns over the long term. The strength and stability of our balance sheet is critical in today's market. Access to capital, sufficient liquidity and quality of earnings are our key drivers.

Our long-term growth strategy is to add and augment revenue streams from our diverse wholesale energy operations. We have implemented a balanced, integrated approach to fuel production, energy marketing and power generation, supported by disciplined risk management practices. Building on the strength of our electric utility, we have enhanced our local operations by providing broadband communications to our customers in South Dakota. Our diverse operations avoid reliance on any single element to achieve our growth objective. This diversity is expected to provide a measure of stability in volatile or cyclical periods.

Prospective Information

We believe we made significant progress in 2003 to position ourselves for a successful future. We strengthened our balance sheet and increased our liquidity through capital market activity, the sale of non-strategic assets and contract restructuring.

We continue to advance our ongoing business strategy. We expect long-term growth through the expansion of integrated, balanced and diverse competitive energy operations supplemented by the strength and stability of our electric utility and improving results from our communication business. We recognize that sustained growth requires continued capital deployment. We believe that we are strategically positioned to take advantage of opportunities to acquire and develop energy assets consistent with our investment criteria and a prudent capital structure.

Our strategy includes the following key elements:

- grow our power generation segment by developing and acquiring power generating assets in targeted Western markets and, in particular, by expanding generating capacity of our existing sites through a strategy known as “brownfield development;
- sell a large percentage of our capacity and energy production from new independent power projects through mid- and long-term contracts in order to secure a stable revenue stream and attractive returns;
- preserve our electric utility’s low-cost rate structure for our residential, commercial and industrial customers while retaining the flexibility to selectively market excess generating capacity off-system to maximize returns in changing market environments;
- expand retail operations through selective acquisitions of electric utilities consistent with our regional focus and strategic advantages;
- increase our reserves of natural gas and crude oil and expand our overall fuel production;
- grow our energy marketing operations primarily through the expansion of producer and end-use origination services;
- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure;
- conduct business with a diversified group of creditworthy or sufficiently collateralized counterparties;
- exploit our fuel cost advantages and our operating and marketing expertise to produce power at attractive margins;
- increase margins from our coal production through an expansion of mine-mouth generation and increased coal sales;
- build and maintain strong relationships with wholesale energy customers;
- create a stronger and financially viable communications business segment by continuing to capitalize on our utility’s established market presence and reputation for customer service and value by increasing revenues, and by creating additional operating efficiencies; and
- organize our lines of business into retail and wholesale energy components. The retail component will consist of electric and telecommunications products and services. The wholesale component will consist of fuel production, marketing, mid-stream assets and power production facilities.

Our wholesale energy group was our largest contributor to revenue and earnings in 2003 and 2002. We expect that earnings from this group over the next few years will be driven primarily by increased oil and gas production; growth in our energy marketing operations through increased marketing volumes, expansion of producer and origination services and transportation arrangements; and expansion in power generation. In March 2003 we acquired Mallon Resources Corporation, an energy company engaged in oil and natural gas exploration, development and production primarily in the San Juan Basin of New Mexico. This acquisition more than doubled our reserves, and contributed to our 42 percent increase in production volumes compared to 2002 pre-acquisition levels. Although we expect long-term growth in our power generation segment, 2004 power generation earnings are expected to decrease from 2003 due to the sale of our hydroelectric power plants, the Las Vegas Cogeneration II contract termination and buyout by Allegheny Energy Supply Company, LLC, the new lower-priced Las Vegas Cogeneration II contract with Nevada Power Company that begins April 1, 2004, partially offset by lower depreciation expense on a decreased plant asset value, and the impact of consolidation of our Variable Interest Entity, Wygen Funding, Limited Partnership (See Note 1 of Notes to the Consolidated Financial Statements).

Our electric utility's retail business remained healthy in 2003. We believe that our electric utility will produce modest growth in revenue, and absent unplanned plant outages, it will continue to produce stable earnings for the next several years. We forecast firm energy sales in our retail service territory to increase over the next 10 years at an annual compound growth rate of approximately one percent, with the system demand forecasted to increase at a rate of two percent. These forecasts are derived from studies conducted by us whereby we examined and analyzed our service territory to estimate changes in the needs for electrical energy and demand over a 20-year period. These forecasts are only estimates, and the actual changes in electric sales may be substantially different. Weather deviations can also affect energy sales significantly when compared to forecasts based on normal weather. The portion of the utility's future earnings that will result from wholesale off-system sales will depend on many factors, including native load growth, plant availability, electricity demand and commodity prices. The completion of construction of the AC/DC/AC (East-West) Tie in the fourth quarter of 2003 provides new marketing opportunities for our utility's excess generation resources through off-system sales.

Although our broadband communications business significantly increased customers in 2003, we expect it will sustain approximately $3.0 to $4.0 million in net losses in 2004. The recovery of our capital investment and future profitability are dependent primarily on our ability to sustain our customer base and control our expenses, and is subject to the risk of market competition and the risk that technological advances may render our network obsolete. If we determine that we will be unable to recover our investment, we would be required to take a non-cash charge to earnings, in an amount that could be material, in order to write down a portion of our investment. While we do not anticipate being regulated in the local markets, we are unable to predict future markets, future government impositions or future economic and competitive conditions that could affect the profitability of the communications operations.

We recognize that long-term growth requires continued capital deployment. We have forecasted $200 million a year for each of the next three years for growth capital deployment. Actual deployment of the capital is dependent on identifying and obtaining or developing projects that meet our investment criteria. In January 2004 we announced that we had entered into a definitive agreement to acquire Cheyenne Light, Fuel & Power (CLF&P) from Xcel Energy Inc. CLF&P is a utility serving residential, commercial and industrial energy consumers in Cheyenne, Wyoming. Currently the utility has approximately 38,000 electric customers and 30,000 gas customers. Its peak load is 156 megawatts and power is provided under an all-requirements contract with Public Service Company of Colorado, which extends through 2007. CLF&P's annual natural gas sales and transportation during 2003 were approximately 16.4 million MMBtus, with sales to commercial and residential customers accounting for approximately 4.5 million MMBtus and transportation accounting for approximately 11.8 million MMBtus. The acquisition is subject to various state and federal regulatory approvals and is expected to be completed by the end of 2004.

Earnings Guidance for 2004

We expect income from continuing operations for the year 2004 to be in the range of $2.00 to $2.35 per share. This guidance is based on the following factors:

- Higher earnings in our oil and gas production segment due to anticipated increases in gas production and strong natural gas prices.

- Higher earnings from our energy marketing segment due to an anticipated increase in natural gas marketing volumes.

- A decrease in expected earnings from our power generation segment due to the sale of our hydroelectric power plants, the Las Vegas Cogeneration II contract termination and buyout of the contract by Allegheny Energy Supply, the new lower-priced Las Vegas Cogeneration II contract with Nevada Power Company that begins April 1, 2004, and the impact of consolidation of Wygen Funding, Limited Partnership.

- An anticipated after-tax loss in our communications segment of approximately $3 to $4 million.

- Higher corporate expenses related to the cost of insurance, compliance and general and administrative functions.
- Higher interest expense due to a full year of our $250 million senior unsecured notes outstanding.
- Deployment of capital in new investment opportunities. The amount and timing of capital deployed may impact our guidance.

Results of Operations

Consolidated Results

Overview

Revenue and income (loss) from continuing operations provided by each business group as a percentage of our total revenue and net income were as follows:

	2003	2002	2001
Revenue:			
Wholesale energy	83%	78%	68%
Electric utility	14	18	29
Communications	3	4	3
	100%	100%	100%

	2003	2002	2001
Income (loss) from continuing operations:			
Wholesale energy	81%	66%	65%
Electric utility	42	51	53
Communications	(10)	(12)	(15)
Corporate	(13)	(5)	(3)
	100%	100%	100%

In 2003, we sold our hydroelectric power plants located in upstate New York. The non-strategic assets were sold effective September 30, 2003. We also developed a plan of sale for our 40 MW Pepperell power plant, our last power plant in the Eastern region. These discontinued operations were previously reported in the Power generation segment. During the second quarter of 2002, we adopted a plan to dispose of our coal marketing subsidiary, Black Hills Coal Network, due primarily to difficulties in marketing our Wyodak coal from the Powder River Basin of Wyoming to Midwestern and Eastern coal markets. We sold the non-strategic assets effective August 1, 2002. These discontinued operations were previously reported in the Energy marketing segment. Results of operations for 2002 and 2001 have been restated to reflect the operations discontinued.

<u>2003 Compared to 2002</u>

Consolidated income from continuing operations for 2003 was $57.0 million, compared to $58.6 million in 2002, or $1.84 per share in 2003, compared to $2.16 per share in 2002. Income from discontinued operations was $9.4 million or $0.30 per share in 2003, compared to $2.0 million or $0.07 per share in 2002. Return on average common equity in 2003 and 2002, was 9.9 percent and 11.8 percent, respectively.

The 2003 results were impacted by an approximate 14 percent increase in diluted weighted average shares outstanding primarily related to the dilutive effect of the April 2003 common stock offering in which 4.6 million shares were issued. In addition, results for 2003 include the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately $1.2 million after-tax. These items include:

- a $3.0 million after-tax charge in our energy marketing segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of $1.9 million in our power generation segment for the impact of a $114.0 million contract termination payment received at the Las Vegas II plant, offset by the related $117.2 million impairment charge taken on that plant;
- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Corporate costs for the year ended December 31, 2003 increased $4.6 million after tax, compared to 2002. The increase is primarily due to a $3.9 million net increase in interest expense, increased health care costs and corporate tax expense. Net interest costs increased due to the low returns on short-term investments compared to interest costs from the $250 million debt issuance in May 2003.

Discussion of results from our operating groups and segments are included in the following pages.

2002 Compared to 2001

Consolidated income from continuing operations for 2002 was $58.6 million, compared to $84.1 million in 2001, or $2.16 per share in 2002, compared to $3.27 per share in 2001. Income from discontinued operations was $2.0 million or $0.07 per share in 2002 compared to $4.0 million, or $0.15 per share, in 2001. Return on average common equity in 2002 and 2001 was 11.8 percent and 22.2 percent, respectively.

The decrease in income from continuing operations was a result of a substantial decrease in prevailing prices for natural gas and wholesale electricity and in gross margins from natural gas marketing activities compared to 2001. Unusual energy market conditions existed in the first half of 2001 stemming primarily from gas and electricity shortages in the West. Approximately $1.40 per share of the 2001 income from continuing operations was attributable to the unusual market conditions that existed at the time. Average wholesale electric average peak prices at Mid-Columbia were approximately $143 per megawatt-hour in 2001 compared to approximately $24 per megawatt-hour in 2002. Average spot market gas prices in the West Coast region were approximately $7 per MMBtu in 2001 compared to $3 per MMBtu in 2002. While these factors negatively impacted income from continuing operations in 2002, they were offset in part by an increase in the production of coal, oil, gas, power generation capacity, and a decrease in the net loss at our communications business group, primarily attributable to the continued expansion of its customer base.

Results in 2002 included a non-recurring after-tax benefit of $1.9 million for collection of previously reserved for amounts at our power generation segment. In addition, 2001 earnings were impacted by several non-recurring items including a $0.17 per share charge for a financial exposure to Enron Corporation, a $0.12 per share charge for employee stock bonus awards and the funding of the Black Hills Corporation Foundation, a $0.06 per share benefit for the sale of coal mining equipment and a $0.13 per share benefit for a gain on a coal contract settlement.

Discussion of results from our operating groups and segments are included in the following pages.

The following business group and segment information does not include discontinued operations or intercompany eliminations. Accordingly, 2002 and 2001 information has been revised to remove information related to operations that were discontinued.

Wholesale Energy Group

	2003	2002	2001
		(in thousands)	
Revenue:			
Power generation	$ 284,567*	$ 102,548	$ 50,228
Energy marketing**	675,586	553,688	390,317
Oil and gas	46,977	26,486	33,408
Coal mining	34,779	31,349	31,800
Total revenue	1,041,909	714,071	505,753
Equity in earnings of unconsolidated subsidiaries	5,747	4,588	14,331
Operating expenses**	(948,990)*	(645,330)	(431,593)
Operating income	$ 98,666	$ 73,329	$ 88,491
Income from continuing operations before change in accounting principles	$ 46,357	$ 38,617	$ 54,457
Changes in accounting principles	(5,195)	896	--
Net income	$ 41,162	$ 39,513	$ 54,457

*Power generation revenue in 2003 includes $114.0 million of contract termination revenue and 2003 operating expenses include $117.2 million of impairment of long-lived assets (see Notes 3 and 4 of the Notes to Consolidated Financial Statements).

**All periods presented reflect a net presentation of revenues at our gas marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

The following is a summary of sales volumes of our coal, oil and natural gas production and our power generation capacity:

	2003	2002	2001
Fuel Production:			
Tons of coal sold	4,812,300	4,052,400	3,518,000
Barrels of oil sold	415,800	452,500	445,500
Mcf of natural gas sold	8,348,400	4,682,600	4,619,500
Mcf equivalent sales	10,843,400	7,397,800	7,292,500
Independent Power Capacity:			
MWs of independent power capacity in service(b)	1,002	950(a)	617
MWs of independent power capacity under construction	--	90	364

(a) Includes the 224 MW expansion at the Las Vegas II power plant which was placed into service on January 3, 2003.

(b) Capacity in service includes 40 megawatt (Pepperell) in 2003 and 82 megawatt and 68 megawatt (Pepperell and hydroelectric) in 2002 and 2001, respectively, which are currently reported as “Discontinued operations.”

The following is a summary of energy marketing average daily volumes:

	2003	2002	2001
Energy Marketing Average Daily Volumes:			
Natural gas - MMBtus	1,241,900	1,088,200	1,047,700
Crude oil - barrels	58,700	57,200	36,500

2003 Compared to 2002

Income from continuing operations from the Wholesale Energy group for 2003 was $46.4 million, compared to $38.6 million in 2002. Results for 2003 include the impact of several non-recurring items that had a net effect of decreasing 2003 results by approximately $1.2 million after-tax. These items include:

- a $3.0 million after-tax charge in our energy marketing segment for a settlement with the Commodity Futures Trading Commission (CFTC);
- a net after-tax charge of $1.9 million in our power generation segment for the impact of a $114.0 million contract termination payment received at the Las Vegas II plant, offset by the related $117.2 million impairment charge taken on that plant;
- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity-method power funds;
- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and
- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts at our power generation segment.

Power generation segment income from continuing operations increased to $22.4 million in 2003 from $12.5 million in 2002, primarily due to earnings from 314 megawatts of additional capacity that was placed into service early in 2003, partially offset by increased related operating, interest and depreciation costs and fourth quarter losses at the 224 megawatt Las Vegas II plant as prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant’s long-term contract. Income from continuing operations from our energy marketing businesses decreased to $6.7 million in 2003, compared to $12.7 million in 2002 primarily due to the CFTC settlement and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. Oil and gas income from continuing operations increased to $8.4 million in 2003 compared to $4.8 million in 2002. Results improved due to a 47 percent increase in volumes sold, primarily related to the March 2003 acquisition of Mallon Resources, and higher prices received during 2003, partially offset by higher depletion and operating costs. Coal mining income from continuing operations in 2003 increased to $8.8 million compared to $8.6 million in 2002, due to a 19 percent increase in tons sold, which was partially offset by higher general and administrative and direct mining costs related to the increased production volumes.

2002 Compared to 2001

Income from continuing operations at our wholesale energy group decreased 29 percent in 2002 compared to 2001. Results decreased primarily due to a substantial decline in energy prices partially offset by growth in the power generation segment. The power generation segment had a substantial increase in earnings primarily due to results from increased capacity that went into service during 2002 and the second half of 2001, additional ownership interest in an energy partnership and a $1.9 million after-tax benefit relating to the collection of receivables reserved for in 2001 from California operations. In addition, 2001 results were impacted by a $4.4 million after-tax charge for credit exposure to Enron Corporation, a $1.7 million after-tax gain on the sale of coal mining equipment and a $3.4 million after-tax gain on the settlement of a coal contract.

The wholesale energy group's revenues increased due to increased crude oil marketing volumes sold at higher prices, increased power generation revenues due to an increase in capacity and acquisition of additional power generation partnership interests, partially offset by lower margins at our gas marketing operations.

The wholesale energy group's total operating expenses increased due to higher cost of crude oil purchases at our crude oil marketing operations, expanded power production, and increased costs of sales related to higher volumes of fuel production and tons of coal sold, partially offset by lower incentive compensation in our energy marketing segment.

Power Generation

Our power generation segment produced the following results:

	2003	2002	2001
		(in thousands)	
Revenue	$ 284,567*	$ 102,548	$ 50,228
Equity in earnings of unconsolidated subsidiaries	5,409	4,339	13,616
Operating income	64,302	39,701	13,050
Income from continuing operations before changes in accounting principles	22,429	12,523	(1,897)
Changes in accounting principles	(2,541)	896	--
Net income (loss)	19,888	13,419	(1,897)

*Power generation revenue in 2003 includes $114.0 million of contract termination revenue (see Note 3 of our Notes to Consolidated Financial Statements).

2003 Compared to 2002

Income from continuing operations increased $9.9 million in 2003 compared to 2002 primarily due to increased generation capacity in operation, partially offset by related increases in interest, depreciation, fuel and other operating costs and fourth quarter losses at the 224 megawatt Las Vegas II plant as the prevailing regional power market conditions limited the economic dispatch subsequent to the termination of the plant's long-term contract in September 2003. In addition, 2003 results include several non-recurring items that had a net effect of increasing 2003 results by $1.8 million after-tax. These items include:

- a net $1.9 million after-tax charge for the impact of a $114.0 million contract termination payment at the Las Vegas II plant, offset by the related $117.2 million impairment charge taken on the plant;

- a $1.8 million after-tax benefit for unrealized gains on plant investments accounted for on a fair value method of accounting at our equity method power fund investments;

- a $1.5 million after-tax benefit from a legal settlement at our Las Vegas II plant; and

- a $0.4 million after-tax benefit from an Enron bankruptcy settlement.

In addition, 2002 results were affected by a non-recurring $1.9 million after-tax benefit for the collection of previously reserved amounts.

Excluding the $114.0 million contract termination revenue and the related $117.2 million asset impairment charge, 2003 revenue and operating expense increased 66 percent and 61 percent, respectively, over 2002. The revenue increase is primarily related to energy sales and capacity payments on the 224 megawatt gas-fired Las Vegas II plant and the 90 megawatt coal-fired Wygen plant, both of which went into operation early in 2003 and the 50 MW Arapahoe expansion completed in the latter part of 2002. The Las Vegas II plant received capacity and energy payments under a long-term contract only through September 22, 2003, the contract termination date. After the contract termination, the Las Vegas II plant sold power into the market when it was economic to do so. In December 2003 a new long-term tolling arrangement was entered into with Nevada Power Company, subject to regulatory approval, which was received on March 3, 2004. Increased operating expense is primarily due to the increased depreciation, fuel, and other operating costs associated with the additional power plants in operation.

Interest expense increased $11.1 million primarily due to interest costs on plant construction projects, completed in the latter part of 2002 and early 2003, being capitalized during construction compared to expensed after the plants became operational.

<u>2002 Compared to 2001</u>

Income from continuing operations increased $14.4 million primarily due to increased capacity that went into service during 2002 and the second half of 2001. During 2002 we had 644 net megawatts of independent power capacity in service, contributing to operations, compared to 549 net megawatts at December 31, 2001. Approximately 300 megawatts of the 549 megawatts of capacity at December 31, 2001 were brought on-line during the third quarter of 2001. Earnings for 2002 also reflect a $1.9 million after-tax benefit relating to the collection of receivables reserved for in prior periods and a $0.9 million benefit, net of taxes from a change in accounting principle related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangibles” (SFAS 142). In addition, 2001 was impacted by a $4.4 million after-tax charge for credit exposure to Enron Corporation.

Revenue increased 104 percent with a corresponding 32 percent increase to operating expenses. Approximately 44 percent of the revenue and 40 percent of the operating expense increases were attributable to the purchase of an additional 30 percent interest in the Harbor Cogeneration Facility (Harbor) on March 15, 2002. Harbor is a 98-megawatt gas-fired plant located in Wilmington, California. Our investment in Harbor prior to this acquisition was accounted for under the equity method of accounting. This acquisition gave us majority ownership and voting control of Harbor, and required us to consolidate Harbor into our financial statements. This consolidation was partially offset by a $6.4 million decrease in equity in earnings of unconsolidated subsidiaries. The remaining increase in revenue and operating expenses was due to the additional generating capacity.

Interest expense increased $3.3 million due to a $170 million increase in debt outstanding related to the expansion of our generation portfolio, partially offset by lower interest rates.

Energy Marketing

Our energy marketing companies produced the following results:

	2003	2002	2001
	(in thousands)		
Revenue**	$ 675,586	$ 553,688	$ 390,317
Equity in earnings of unconsolidated subsidiaries	--	249	715
Operating income	12,151	18,065	53,662
Income from continuing operations before change in accounting principle	6,725	12,739	34,566
Change in accounting principle	(2,871)	--	--
Net income	3,854	12,739	34,566

**All periods presented reflect a net presentation of revenues at our gas marketing subsidiary and a gross presentation of revenues at our crude oil marketing subsidiary in accordance with EITF 02-3 and EITF 99-19.

2003 Compared to 2002

Income from continuing operations decreased $6.0 million due to a $3.0 million after-tax charge for a settlement with the Commodity Futures Trading Commission (CFTC) and a 10 percent decrease in natural gas margins received, partially offset by a 14 percent increase in natural gas volumes marketed and increased earnings from oil pipelines. In addition, as a result of changing commodity prices, results were impacted by unrealized gains recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market gains were $2.6 million in 2003 compared to losses of $0.9 million in 2002, resulting in a year-over-year increase of $3.5 million, pre-tax.

Revenues increased 22 percent from 2002 due to a 3 percent increase in average daily volumes of crude oil marketed at average prices 20 percent higher than 2002. These higher revenues were substantially offset by increased operating expenses for the purchases of crude oil used in marketing.

2002 Compared to 2001

Income from continuing operations decreased $21.8 million due substantially to high gas margins received in the first half of 2001, partially offset by a 4 percent increase in natural gas average daily volumes marketed, a 57 percent increase in average daily volumes of crude oil marketed and lower commissions and incentive compensation in 2002.

Revenues increased 42 percent from 2001 primarily due to a 57 percent increase in crude oil volumes marketed with a 7 percent increase in average prices. In addition, we had higher revenues from increased pipeline operations offset by lower natural gas margins. Lower natural gas marketing margins resulted from unusual energy marketing conditions that existed in the first six months of 2001, stemming primarily from gas and electricity shortages in the West. Average spot market gas prices in the West Coast region were approximately $7 per MMBtu in 2001 compared to $3 per MMBtu in 2002. The substantial increase in average daily volumes of crude oil marketed was due to oil marketing contracts that we entered into in 2002 that did not extend beyond January 2003.

As a result of changing commodity prices, net income was impacted by unrealized gains recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market losses were $0.9 million in 2002 compared to gains of $1.8 million in 2001, resulting in a year-over-year decrease of $2.7 million pre-tax.

In addition to substantial increases in operating expenses related to purchases of crude oil, which offset the increased revenues from crude oil marketing sales, we had a $17.1 million decrease in commissions and incentive compensation related to the decrease in profitability in this segment, partially offset by additional expenses associated with our additional ownership interests in oil pipelines.

Oil and Gas

Oil and gas operating results were as follows:

	2003	2002	2001
	(in thousands)		
Revenue	$ 46,977	$ 26,486	$ 33,408
Equity in earnings of unconsolidated subsidiary	338	--	--
Operating income	13,596	6,471	15,193
Income from continuing operations before change in accounting principle	8,400	4,783	10,197
Change in accounting principle	(128)	--	--
Net income	8,272	4,783	10,197

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

	2003	2002	2001
Barrels of oil (in thousands)	5,389	4,880	4,055
Mmcf of natural gas	124,062	28,513	24,071
Total in Mmcf equivalents	156,399	57,793	48,401

These reserves are based on reports prepared by Ralph E. Davis Associates, Inc., an independent consulting and engineering firm. Reserves were determined using constant product prices at the end of the respective years. Estimates of economically recoverable reserves and future net revenues are based on a number of variables, which may differ from actual results. Reserves at December 31, 2003 include the March 10, 2003 acquisition of Mallon Resources Corporation. Reserves reflect an oil price of $32.52 per barrel and a natural gas price of $6.15 per Mcf as of December 31, 2003; $31.20 per barrel and $4.60 per Mcf as of December 31, 2002 and $19.84 per barrel and $2.57 per Mcf as of December 31, 2001.

2003 Compared to 2002

Income from continuing operations increased $3.6 million due to a 42 percent increase in volumes sold, primarily related to production from properties acquired in the March 2003 Mallon Resources acquisition. Average gas and oil prices received in 2003 were $3.67/Mcf and $24.70/bbl, respectively, compared to $2.45/Mcf and $23.01/bbl in 2002. Total operating expenses increased 69 percent primarily related to the additional operations acquired in the Mallon transaction. In addition, 2003 lease operating expenses per Mcfe produced (LOE/MCFE) increased 37 percent over 2002; and 2003 depletion per Mcfe produced decreased 8 percent compared to 2002.

Additional information on our Oil and Gas properties can be found in Note 21 to our Notes to Consolidated Financial Statements.

2002 Compared to 2001

Income from continuing operations decreased 53 percent, or $5.4 million, primarily due to a $6.9 million decrease in revenues. The decrease in revenues was due to a 26 percent decrease in the average oil and natural gas price received, partially offset by a slight increase in production volumes. The average gas and oil prices received in 2002 were $2.45/Mcf and $23.01/bbl, respectively compared to $3.90/Mcf and $24.30/bbl in 2001.

Coal Mining

Coal mining results were as follows:

	2003	2002	2001
	(in thousands)		
Revenue	$ 34,779	$ 31,349	$ 31,800
Operating income	8,617	9,092	6,586
Income from continuing operations before change in accounting principle	8,803	8,572	11,591
Change in accounting principle	345	--	--
Net income	9,148	8,572	11,591

2003 Compared to 2002

Income from continuing operations increased $0.2 million due to a 19 percent increase in tons sold, partially offset by a 6 percent decrease in average sales price per ton and an increase in general and administrative and direct mining costs related to the increased production. Increased coal tons sold were the result of sales to our 90 megawatt Wygen power plant that became operational in February 2003 and additional sales through our train load-out facility.

2002 Compared to 2001

Income from continuing operations decreased $3.0 million as a result of earnings benefits in 2001 from a $3.4 million after-tax gain on a coal contract settlement and a $1.7 million after-tax gain on the sale of mining equipment. Coal mining revenue decreased slightly due to a 14 percent decrease in the average price received per ton of coal offset by a 15 percent increase in tons of coal sold.

Operating expenses decreased 12 percent, or approximately $3.0 million, primarily due to reduced production and severance taxes, reduced royalty expense and capitalization of overburden costs related to developing a new mining area.

Electric Utility Group

	2003	2002	2001
	(in thousands)		
Revenue	$ 171,019	$ 162,186	$ 212,355
Operating expenses	119,920	104,026	128,247
Operating income	$ 51,099	$ 58,160	$ 84,108
Income from continuing operations and net income	$ 24,089	$ 30,217	$ 45,238

The following table provides certain electric utility operating statistics:

	2003	2002	2001
Firm electric sales - MWh	1,994,819	1,966,060	2,012,354
Wholesale off-system - MWh	930,706	979,677	965,030

We currently have a winter peak load of 344 megawatts established in December 1998 and a summer peak load of 392 megawatts established in August 2001. We own 435 megawatts of electric utility generating capacity and purchase an additional 50 megawatts under a long-term agreement.

2003 Compared to 2002

Electric revenue increased 5 percent in 2003 compared to 2002, primarily due to an 18 percent increase in wholesale off-system sales at an average price that was 24 percent higher than the average price in 2002.

Firm kilowatt-hour sales increased 1 percent. Residential and commercial sales increases of 2 percent and 3 percent, respectively, in 2003 accounted for a $2.1 million increase in revenue. The 18 percent increase in wholesale off-system sales accounted for a $5.8 million increase in revenues. These increases were offset by a 4 percent decrease in industrial sales, primarily due to the closing of Homestake Mine, which had been one of our largest customers.

Revenue per kilowatt-hour sold was 5.6 cents in 2003 compared to 5.3 cents in 2002. The number of customers in the service area increased to 61,148 in 2003 from 59,948 in 2002.

Electric utility operating expenses increased $15.9 million due to a $10.1 million increase in fuel and purchased power cost, a $3.7 million increase in certain operations and maintenance costs, including pension expense, a $1.5 million increase in depreciation expense and a $2.5 million increase in interest expense due to the full year impact of $75 million of first mortgage bonds issued in August 2002.

The increase in fuel cost was due to a 77 percent increase in average gas prices for combustion turbine generation facilities and a 19 percent increase in average megawatt-hour purchased power costs.

2002 Compared to 2001

Electric revenue decreased 24 percent in 2002 compared to 2001. The decrease in electric revenue in 2002 was due to a $52.9 million decrease in wholesale off-system sales at an average price that was 63 percent lower than the average price in 2001.

Firm kilowatt-hour sales decreased 2 percent in 2002. Residential and commercial sales increases of 5 percent and 3 percent, respectively, in 2002 accounted for a $2.9 million increase in revenue, which was offset by a $3.6 million decrease in industrial sales, primarily due to discontinued operations at two of our largest and oldest customers, Homestake Gold Mine and Federal Beef Processors. Degree days, a measure of weather trends, were one percent above normal in 2002 and four percent above 2001.

Revenue per kilowatt-hour sold was 5.3 cents in 2002 compared to 7.0 cents in 2001. The number of customers in the service area at December 31, 2002 increased to 59,948 from 59,237 in 2001. The decrease in the revenue per kilowatt-hour sold in 2002 is due to a 63 percent decrease in average wholesale off-system prices.

Electric utility operating expenses decreased $24.2 million, or 19 percent, in 2002. The decrease was primarily due to a $22.0 million decrease in fuel and purchased power costs and a $5.0 million decrease in operations and maintenance expenses, offset by higher depreciation expense related to the addition of the Lange combustion turbine in early 2002.

The decrease in fuel and purchased power costs was primarily due to the high spot market price for gas and electricity in the first half of 2001. The decrease in operations expense was primarily due to a $3.2 million expense of a temporary generator lease in 2001 and a $3.1 million decrease in incentive compensation in 2002 offset by a $1.8 million increase in pension expense in 2002.

Net interest expense increased $2.3 million due to the issuance of $75 million of first mortgage bonds in August 2002.

In addition, 2001 earnings included a $2.0 million after-tax charge related to the formation of the Black Hills Corporation Foundation.

Communications Group

	2003	2002	2001
		(in thousands)	
Revenue	$ 39,763	$ 32,677	$ 20,258
Operating expenses	45,004	40,124	33,508
Operating loss	$ (5,241)	$ (7,447)	$ (13,250)
Loss from continuing operations and net loss	$ (5,880)	$ (7,260)	$ (12,300)

	2003	2002	2001
Residential customers	23,878	21,700	15,660
Business customers	3,012(a)	3,061	2,250
Fiber optic backbone miles	245	242	242
Hybrid fiber coaxial cable miles	840	818	737

(a) In 2003, reported business customers were adjusted for the consolidation of multiple-location business customers, business orders and temporary business access lines.

In September 1998, we formed our broadband communications business to provide facilities-based communications services for Rapid City and the Northern Black Hills of South Dakota. As of December 31, 2003, we had invested approximately $158 million in state-of-the-art technology that offers local and long distance telephone service, expanded cable television service, Internet access, and high-speed data and video services. We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers.

2003 Compared to 2002

Loss from continuing operations was $5.9 million in 2003 compared to $7.3 million in 2002. The improved performance was due to increased revenues from a larger customer base and an additional $2.4 million in revenues from a successful directory publication and distribution, partially offset by $0.5 million in sales incentive costs related to a current marketing campaign responding to recent competitive pressures. Revenue increases were also partially offset by a $2.0 million increase in cost of sales and a $1.8 million increase in depreciation expense. In addition, 2002 results included a $0.6 million after-tax benefit from the collection of previously reserved amounts.

2002 Compared to 2001

Our customer base increased 38 percent in 2002 to 21,700 residential customers and 3,061 business customers. A $12.4 million increase in revenues from a larger customer base in 2002 was partially offset by a $3.0 million increase in cost of sales, a $1.9 million increase in operations and maintenance expenses and a $2.7 million increase in depreciation costs. Interest expense decreased $1.9 million due to lower interest rates partially offset by higher balances. The $7.3 million loss in 2002 represents a 41 percent improvement over the $12.3 million loss in 2001.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. The significant accounting policies which we believe are the most critical in understanding and evaluating our reported financial results include the following:

Impairment of Long-lived Assets

We evaluate for impairment, the carrying values of our long-lived assets, including goodwill and other intangibles, whenever indicators of impairment exist and at least annually for goodwill as required by SFAS 142.

For long-lived assets with finite lives, this evaluation is based upon our projections of anticipated future cash flows (undiscounted and without interest charges) from the assets being evaluated. If the sum of the anticipated future cash flows over the expected useful life of the assets is less than the assets' carrying value, then a permanent non-cash write-down equal to the difference between the assets' carrying value and the assets' fair value is required to be charged to earnings. In estimating future cash flows, we generally use a probability weighted average expected cash flow method with assumptions based on those used for internal budgets. Although we believe our estimates of future cash flows are reasonable, different assumptions regarding such cash flows could materially affect our evaluations.

As a result of the transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, for capacity and energy at the Company's Las Vegas Cogeneration II power plant, we assessed the recoverability of the carrying value of the facility. The carrying value of the assets tested for impairment was $237.2 million. This assessment resulted in a pre-tax impairment charge of $117.2 million to write-down the related property, plant and equipment by $83.1 million, net of accumulated depreciation of $5.1 million, and intangible assets by $34.1 million, net of accumulated amortization of $1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows.

In measuring the fair value of the Las Vegas II power plant and the resulting impairment charge, we considered a number of possible cash flow models associated with the various probable operating assumptions and pricing for the capacity and energy of the facility. We then made our best determination of the relative likelihood of the various models in computing a weighted average expected cash flow for the facility. Inclusion of other possible cash flow scenarios and/or different weighting of those that were included could have led to different conclusions about the fair value of the plant. Further, the weighted average cash flow method is sensitive to the discount rate assumption. If we had used a discount rate that was 1 percent higher, the resulting impairment charge would have been approximately $7.0 million higher. If the discount rate would have been 1 percent lower, the impairment charge would have been approximately $8.0 million lower.

Our Communications business segment began providing broadband communications services in November 1999 and since that time has not achieved profitability. In each of the last four years, we have evaluated the assets of our Communications business segment for impairment, and in each year we determined, based on our assumptions, that the sum of the anticipated future cash flows (undiscounted and without interest charges) exceeded the carrying value and, therefore, we did not recognize an impairment. The carrying value of the assets tested for impairment was approximately $115 million at December 31, 2003. Any increases in the anticipated future cash flows would have no impact on the carrying value of these assets. If our current estimates of future cash flows from the operation of these assets had been 10 percent lower, we still would not have been required to record an impairment charge.

For long-lived assets with indefinite lives, SFAS 142 requires an annual impairment test. Upon adopting SFAS 142 on January 1, 2002, we completed a transition impairment test in the first quarter of 2002. As a result of this impairment test, we recognized a $0.8 million after-tax impairment charge related to the goodwill at our discontinued coal marketing operations. This impairment charge is reported as part of Income from discontinued operations, net of taxes on the 2001 Consolidated Statement of Income. This impairment charge was offset by income of $0.9 million, after-tax, from the write-off of negative goodwill at our power generation segment, as required by SFAS 142. This amount is reported as “Change in accounting principles, net of taxes” on the 2002 Consolidated Statement of Income. We completed our 2003 annual goodwill impairment test in the fourth quarter. This test did not result in an additional impairment.

Full Cost Method of Accounting for Oil and Gas Activities

We account for our oil and gas activities under the full cost method whereby all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a “ceilings test” that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon actual oil and gas prices at the end of each reporting period adjusted for contracted price changes. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Although our net capitalized costs were less than the full cost ceiling at December 31, 2003, we cannot assure you that a write-down in the future will not occur depending on oil and gas prices at that point in time. In addition, we rely on an independent consulting and engineering firm to determine the amount of our proved reserves and those estimates are based on a number of assumptions about variables. We cannot assure you that these assumptions will not differ from actual results.

Risk Management Activities

We enter into derivative instruments, including options, swaps, futures, forwards and other contractual commitments for both non-trading (hedging) and trading purposes. In addition to the information provided below, see Note 2 of our Notes to Consolidated Financial Statements.

Non-trading (Hedging)

Our typical non-trading (hedging) transactions relate to contracts we enter into at our oil and gas exploration and production subsidiary to fix the price received for anticipated future production and interest rate swaps we enter into to convert a portion of our variable rate debt to a fixed rate. For these and similar transactions, we utilize hedge accounting treatment under SFAS 133 “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133). As cash flow hedges, these derivative instruments are recorded at fair value on the Consolidated Balance Sheets and the effective portion of the gain or loss is reported in other comprehensive income and the ineffective portion in earnings.

Energy Trading and Marketing

Our natural gas marketing operations currently fall under the purview of Emerging Issues Task Force Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3), SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. All of our natural gas contracts meet the definition of a derivative as defined by SFAS 133 and are accounted for under the mark-to-market method of accounting. This mark-to-market process recognizes changes in the value of trading portfolios associated with market price fluctuations. The current fair values of natural gas trading contracts are recorded on the Consolidated Balance Sheets and any period-to-period change in the current fair value of such contracts is recognized in the Consolidated Statements of Income. We have presented the unrealized and realized gains and losses, whether or not settled financially or physically, from the activities of our natural gas marketing business, net in Operating revenues on the Consolidated Statements of Income.

For our crude oil marketing operations, substantially all crude oil contracts historically met the definition of “energy trading activities” under EITF 98-10. Accordingly, all contracts at these operations that originated on or before October 25, 2002 have been accounted for at fair value. With the adoption of EITF 02-3, the contracts at our crude oil marketing operations are no longer recorded at fair value since they do not meet the definition of derivatives or have been exempted from mark-to-market accounting as normal purchase and normal sales contracts. These contracts are accounted for under the accrual method of accounting.

Valuation

Fair values of derivative instruments and energy trading contracts are based on listed market prices, where possible. If market prices are not available, fair value is determined based on other relevant factors and pricing models that consider current market and contractual prices for the underlying financial instruments or commodities, as well as time value and yield curve or volatility factors underlying the positions.

Pricing models and their underlying assumptions impact the amount and timing of unrealized gains and losses recorded, and the use of different pricing models or assumptions could produce different financial results. Changes in the commodity markets will impact our estimates of fair value in the future. To the extent financial contracts have extended maturity dates, our estimates of fair value may involve greater subjectivity due to the lack of transparent market data available upon which to base modeling assumptions.

Counterparty Credit Risk

We perform ongoing credit evaluations of our customers and adjust credit and tenor limits based upon payment history and the customer’s current creditworthiness, as determined by our review of their current financial information. We continuously monitor collections and payments from our customers and maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and established provisions, we cannot assure you that our credit losses will be consistent with our estimates.

Pension and Other Postretirement Benefits

The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions used by actuaries in calculating the amounts. Those assumptions, as further described in Note 15 of our Notes to the Consolidated Financial Statements, include, among others, the discount rate, the expected long-term rate of return on plan assets and the rate of increase in compensation levels and healthcare costs. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

Defined Benefit Pension Plan

We account for our defined benefit pension plan in accordance with SFAS 87, “Employers’ Accounting for Pensions” (SFAS 87). In accordance with SFAS 87, changes in pension obligations associated with fluctuations in long-term actuarial assumptions may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of the plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. For the years ended December 31, 2003, 2002 and 2001, we recorded non-cash (expense) income related to our pension plans of approximately $(3.2) million, $(0.2) million, and $2.1 million, respectively.

Our pension plan assets are held in trust and primarily consist of equity securities and cash equivalents. Fluctuations in actual equity market returns result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

In selecting an assumed rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan and weight the returns by applying the assumed rate of return for each asset class to the target allocation for each asset class in the portfolio. The value of our qualified pension plan assets increased $16.4 million to $48.8 million as of September 30, 2003, due to our $10.5 million contribution to the plan and improved performance of the stock market during 2003. Plan assets earned $8.1 million in 2003. The market value of the plan’s assets had previously been affected by sharp declines in equity markets in 2001 and 2002. Plan assets lost $6.5 million and $13.1 million during 2002 and 2001, respectively. In the recently completed actuarial valuation, for determining our 2004 pension expense, we decreased the assumed rate of return on plan assets from 10 percent to 9.5 percent. This change is expected to increase pension costs in 2004 and beyond by approximately $0.2 million per year. The expected long-term rate of return on plan assets was 10 percent and 10.5 percent for the 2003 and 2002 plan years, respectively.

The 10 percent assumed rate of return for the 2003 plan year was determined based on the following estimated long-term investment allocations and asset class returns:

Asset Class	Estimated Allocation	Estimated Return	Weighted Average Return
Equity	90%	10.5%	9.5%
Fixed Income	5	6.0	0.3
Cash	5	4.0	0.2
	100%		10.0%

The long-term estimated return on the equity component was derived from long-term historical equity returns. We reviewed annual 20-, 30-, 40- and 50-year returns on the S&P 500 Index, which were, at December 31, 2002, 12.5 percent, 10.5 percent, 10.3 percent and 10.9 percent respectively. Estimated expense ratios were based on current expense ratios of 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The long-term estimated fixed income return was estimated based on the historical annual returns on intermediate-term treasury bonds returns of 6.3 percent from 1950 to 2002. Cash returns are estimated to be approximately 200 basis points below intermediate-term treasury bonds.

If we had decreased our expected long-term rate of return on our plan assets by 0.5 percent in 2003, pension expense would have increased by approximately $0.2 million.

The discount rate we utilize for determining future benefit obligations is based on high grade bond rates. The discount rate was decreased to 6.75 percent for the 2003 pension cost determination from 7.5 percent in 2002. The 2004 net periodic pension costs have been calculated using a 6 percent discount rate. A 0.5 percent decrease in the discount rate will cause pension expense to increase by approximately $0.5 million.

Based on our recently completed plan forecasts, we estimate that we will not be required to make cash contributions to the pension plan during the next five years.

Actual pension expense and contributions required will depend on future investment performance, changes in future discount rates, the level of contributions we make and various other factors related to the populations participating in the pension plan. We will continue to evaluate all of the actuarial assumptions, generally on an annual basis, including the expected long-term rate of return on assets and discount rate, and will adjust the assumptions as necessary.

Non-qualified Pension Plans

We have various supplemental retirement plans for our outside directors and key executives. The plans are nonqualified defined benefit plans accounted for in accordance with SFAS 87. Expenses recognized under the plans were $1.7 million in 2003, $0.8 million in 2002, and $0.5 million in 2001. The plans are unfunded. The actuarial assumptions used for our non-qualified pension plans are the same as those used in our qualified plan.

Other Postretirement Benefits

We account for our other postretirement benefit costs in accordance with SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106). We do not pre-fund our other postretirement benefit plan. Our reported costs of providing other postretirement benefits are dependent upon numerous factors, including health care cost trends, and result from actual plan experience and assumptions of future experience. As a result of these factors, significant portions of other postretirement benefit costs recorded in any period do not reflect the actual benefits provided to plan participants. For the years ended December 31, 2003, 2002 and 2001, we recorded other postretirement benefit expense of approximately $1.2 million, $1.0 million and $1.0 million, respectively, in accordance with SFAS 106. Actual payments of benefits to retirees during these periods were approximately $0.6 million per year.

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

Change in Assumption	Impact on December 31, 2003 Accumulated Postretirement Benefit Obligation (in thousands)	Impact on 2003 Service and Interest Cost
Increase 1%	$ 1,574	$ 211
Decrease 1%	$ (1,248)	$ (163)

In selecting assumed health care cost trend rates, we consider recent plan experience and various short and long-term cost forecasts for the healthcare industry. Based on these considerations we have changed the health care cost trend rate used by the actuaries to determine our other postretirement benefit expense, for 2004 and beyond, from 11 percent decreasing gradually to 5 percent, to 12 percent in 2004 decreasing gradually to 5 percent in 2011. These changes will increase the future other postretirement benefit expense included on our income statement by approximately $0.2 million. Our discount rate assumption for postretirement benefits is consistent with that used in the calculation of pension benefits. See the Defined Benefit Pension Plan discussion above regarding our discount rate assumptions.

Liquidity and Capital Resources

Overview

Information about our financial position as of December 31, 2003 and 2002, is presented in the following table:

Financial Position Summary	2003	2002	% Change
(in thousands)			
Cash and cash equivalents	$ 172,771	$ 75,045	130%
Short-term debt	17,659	355,824	(95)
Long-term debt	868,459	540,958	61
Stockholders' equity	709,747	535,163	33
Ratios			
Long-term debt ratio	55.0%	50.3%	9%
Total debt ratio	55.5	62.6	(11)

Our liquidity position was greatly enhanced in 2003 due to the public offering of 4.6 million shares of common stock and $250 million of ten-year, senior unsecured notes, the sale of non-strategic assets, and receipt of funds from the termination of a power plant contract.

In 2004, we expect our beginning cash balance, cash provided from operations, and available credit facilities to be sufficient to meet our normal operating commitments, to fund planned capital expenditures and to pay dividends. We would expect to fund a significant portion of any additional investment in power generating facilities with long-term, non-recourse project level debt.

Cash Flow Activities

2003

In 2003, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay our scheduled long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily through a combination of cash on hand and operating cash flow.

Cash flows from operations decreased $38.3 million over the prior year amount, primarily due to a $37.1 million decrease in the year over year change in deferred taxes and a $136.7 million decrease in the change in operating assets and liabilities, offset by the net effect of the Las Vegas II power plant sales contract termination and related impairment charge and a $16.9 million increase in depreciation and depletion expense. In 2002, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with accelerated depreciation and expenses related to our large capital investment in power generation assets in 2002 and 2001. In 2003, the change in our deferred tax liability returned to a more normal level. During the third quarter of 2003, we received $114 million from Allegheny Energy Supply Company, LLC for the termination of a fifteen-year contract for capacity and energy at our Las Vegas II power plant.

We had cash inflows from investing activities of $77.8 million, which includes approximately $186 million from the sale of seven hydroelectric power plants located in upstate New York, partially offset by $104.5 million for property, plant and equipment additions and the acquisition of assets. We had cash outflows from financing activities of $150.7 million, primarily due to the repayment of $139.3 million debt, offset by the net proceeds of $118.0 million from a public offering of 4.6 million shares of common stock and the sale of $250 million ten-year notes. A detailed description of the significant investing and financing activities follows:

- On April 30, 2003, we completed a public offering of 4.6 million shares of common stock at $27 per share. Net proceeds were approximately $118 million after commissions and expenses. The proceeds were used to pay off a $50 million credit facility due in May 2003 and to repay $68 million under our 364-day revolving credit facility which expired on August 26, 2003.

- On May 21, 2003, we issued $250 million 6.5 percent ten-year, senior unsecured notes. Net proceeds from the note offering were approximately $247 million after the discount, commissions and expenses. The proceeds were used to repay our $35 million term loan due September 30, 2004, all of our short-term borrowings under our $195 million, 364-day revolving credit facility and all of our outstanding notes payable under our three-year revolving credit facility which expires on August 24, 2004.

- In August 2003, we closed on a $225 million multi-year, unsecured revolving credit facility that expires on August 20, 2006. The credit facility replaced the $195 million facility that expired in August 2003 and supplements the $200 million facility that expires in August 2004. We had no borrowings outstanding under these facilities as of December 31, 2003. After inclusion of applicable letters of credit, the remaining borrowing capacity under the facilities was $370.7 million at December 31, 2003.

- In September 2003, we paid off all of the project-level debt and related interest rate swaps totaling $91.1 million associated with the seven hydroelectric power plants that were sold.

2002

In 2002, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay a portion of our long-term debt maturities and to fund a portion of our property additions. We funded property and investment additions primarily related to construction and acquisition of additional electric generation facilities for our wholesale energy group through a combination of operating cash flow, increased short-term debt, long-term debt and long-term non-recourse project financing.

Cash flows from operations increased $44.6 million, due to a $17.9 million increase in deferred income taxes and a $15.8 million increase in depreciation expense, offset primarily by the decrease in net income and the provision for valuation allowances. During 2002, we recognized a substantial increase in our deferred income tax liability due to timing differences associated with accelerated depreciation and expenses related to our large capital investment in power generation assets in 2002 and 2001. In 2001, our provision for valuation allowances was larger than normal due to a $6.0 million pre-tax reserve recognized for credit exposure to Enron, a $1.2 million reserve recognized in 2001 for exposure to California markets which was recovered in 2002 and provisions recognized for inventory valuations in our communications group.

During 2002, we had cash outflows for investing activities of $304.4 million, which includes $231.7 million for property, plant and equipment additions and $70.8 million related to acquisitions. Net cash inflows from financing activities totaled $144.2 million. A detailed description of the significant investing and financing activities follows:

- On March 8, 2002, we acquired an additional 67 percent interest in Millennium Pipeline Company, L.P., which owns and operates a 200-mile pipeline, and an additional ownership interest in Millennium Terminal Company, L.P., which has 1.1 million barrels of crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont, Texas. Total cost of the acquisition was $11.0 million and was funded through borrowings under short-term revolving credit facilities.

- On March 14, 2002, we closed on $135 million five-year senior secured project-level financing for the Arapahoe and Valmont facilities. These projects have a total of 210 megawatts in service and are located in the Denver, Colorado area. Proceeds from this financing were used to replace an existing $53.8 million seven-year, secured term project-level facility, pay down approximately $50 million of short-term credit facility borrowings, and the remainder was used for project construction.

- On March 15, 2002, we acquired an additional 30 percent interest in the Harbor Cogeneration Facility, a 98-megawatt gas-fired plant located in Wilmington, California for $25.7 million. This acquisition was also funded through borrowings under short-term revolving credit facilities.

- During the first quarter of 2002, we completed a $50 million bridge credit agreement. The credit agreement supplemented our revolving credit facilities and had the same terms as those facilities with an original expiration date of June 30, 2002, which subsequently was extended to September 27, 2002. On September 27, 2002 this $50 million facility was replaced by a $50 million secured financing for the expansion at our Las Vegas II project which was repaid in May 2003. This financing was guaranteed by Black Hills Corporation.

- On June 18, 2002, we closed on a $75 million bridge credit agreement. This credit agreement bridged the issuance of $75 million of Black Hills Power First Mortgage bonds, which we issued on August 13, 2002. The termination date of the bridge credit agreement was August 13, 2002, the date on which the First Mortgage Bonds were issued.

- During July 2002, we purchased the assets of the Kilgore to Houston Pipeline System from Equilon Pipeline Company, LLC. The Kilgore pipeline transports crude oil from the Kilgore, Texas region south to Houston, Texas, which is the transfer point to connecting carriers via the Oil Tanking Houston terminal facilities. This pipeline is approximately 190 miles long and has a capacity up to approximately 35,000 barrels per day. In addition, the Kilgore system has approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas. Total cost of the acquisition was $6.7 million and was funded through borrowings under short-term credit facilities.

- On August 13, 2002, our electric utility subsidiary, Black Hills Power, Inc., issued $75 million of First Mortgage Bonds, Series AE, due 2032. The mortgage bonds have a 7.23 percent coupon with interest payable semiannually. Net proceeds from the offering were used to fund our utility’s portion of the construction and installation costs for an AC-DC-AC Converter Station, which was completed in 2003; for general capital expenditures for the remainder of 2002 and 2003; to repay a portion of short-term bank indebtedness; to satisfy bond maturities for certain outstanding first mortgage bonds due in 2003; and for general corporate purposes.

- In August 2002, we closed on a $195 million revolving unsecured credit facility with an expiration date of August 26, 2003. The credit facility extended our previous $200 million 364-day credit facility that expired on August 27, 2002.

- On September 25, 2002, we closed on a $35 million unsecured two-year credit agreement. Proceeds were used to fund our working capital needs and for general corporate purposes.

- On October 1, 2002, we entered into a definitive merger agreement to acquire Denver-based Mallon Resources Corporation, an oil and gas exploration and production company. The acquisition was completed on March 10, 2003, whereby each shareholder of Mallon received 0.044 of a share of Black Hills Corporation common stock for each share of Mallon common stock. Total cost of the acquisition was approximately $53 million, which includes our acquisition on October 1, 2002 of Mallon’s debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges, totaling $30.5 million.

- During the fourth quarter of 2002, we purchased the remaining ownership interests in the Harbor Cogeneration Facility and the Pepperell Facility, a 40 megawatt gas-fired plant located in Pepperell, Massachusetts for $13.8 million, giving us 100 percent ownership interests in the facilities. These acquisitions were funded through borrowings under short-term revolving credit facilities.

- On December 18, 2002, we closed on a $27.5 million eight-year financing secured by our 40 megawatt Gillette Combustion Turbine. On the same date, we also closed on a $4.5 million eight-year financing secured by a LM6000 spare turbine. Proceeds were used to pay down short-term credit facility borrowings.

Dividends

Dividends paid on our common stock totaled $1.20 per share in 2003. This reflected increases approved by our board of directors from $1.16 per share in 2002 and $1.12 per share in 2001. All dividends were paid out of current earnings. Our three-year annualized dividend growth rate was 3.6 percent. In January 2004, our board of directors increased the quarterly dividend 3.3 percent to 31 cents per share. If this dividend is maintained during 2004, it will be equivalent to $1.24 per share, an annual increase of 4 cents per share. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Short-Term Liquidity

Our principal sources of short-term liquidity include our cash on hand, our revolving bank facilities and cash provided by operations. As of December 31, 2003 we had approximately $172.8 million of cash unrestricted for operations and $425 million of credit through revolving bank facilities. Approximately $12.4 million of the cash balance at December 31, 2003 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company. The bank facilities consist of a $225 million facility due August 20, 2006 and a $200 million facility due August 27, 2004. These bank facilities can be used to fund our working capital needs, for general corporate purposes, and to provide liquidity for a commercial paper program if implemented. At December 31, 2003, we had no bank borrowings outstanding under these facilities. After inclusion of applicable letters of credit, the remaining borrowing capacity under the bank facilities was $370.7 million at December 31, 2003.

The above bank facilities include the following covenants that are common in such arrangements:

- a consolidated net worth in an amount of not less than the sum of $475 million and 50 percent of our aggregate consolidated net income beginning April 1, 2003;

- a recourse leverage ratio not to exceed 0.65 to 1.00;

- and a fixed charge coverage ratio of not less than 1.5 to 1.0.

If these covenants are violated, it would be considered an event of default entitling the lender to terminate the remaining commitment and accelerate all principal and interest outstanding. In addition, certain of our interest rate swap agreements with a $25 million notional amount at December 31, 2003 include cross-default provisions. These provisions would allow the counterparty the right to terminate the swap agreement and liquidate at a prevailing market rate in the event of default. As of December 31, 2003, we were in compliance with the above covenants.

The $200 million three-year credit facility that expires in August 2004 previously contained a liquidity covenant that required us to have $30 million of liquid assets as of the last day of each fiscal quarter. This covenant was removed from the credit facility through an amendment in August 2003.

Our liquidity position was significantly strengthened in 2003 due to the proceeds from the public offering of 4.6 million shares of common stock and $250 million of ten-year, senior unsecured notes, the sale of the seven hydroelectric power plants, and the $114 million received for the Las Vegas II power plant contract termination (see discussion above under Impairment of Long-Lived Assets). The common stock and ten-year note offerings were completed in the second quarter of 2003 and provided net proceeds of approximately $365 million which were used to pay off the $50 million credit facility due in May 2003, the $35 million term loan due September 2004, all of our borrowings under our 364-day revolving credit facility which expired on August 26, 2003, and all of our notes payable under our three-year revolving credit facility which expires on August 27, 2004. The sale of the seven hydroelectric power plants provided approximately $186 million of cash and was used in part to pay off the remaining amount of project-level debt and related interest rate swaps associated with the hydroelectric power plants, which totaled approximately $91 million. A portion of the proceeds from the sale of the hydroelectric power plants and the $114 million termination payment was used to pay approximately $51 million in income taxes primarily related to those transactions and the remaining proceeds will be used to reduce debt and for other corporate purposes. On January 30, 2004, we used a portion of the proceeds to repay $45 million of our long-term debt outstanding on our Fountain Valley project.

Our consolidated net worth was $709.7 million at December 31, 2003, which was approximately $211.2 million in excess of the net worth we are required to maintain under the debt covenant described above. The long-term debt component of our capital structure at December 31, 2003 was 55.0 percent, our total debt leverage ratio was 55.5 percent and our recourse leverage ratio was approximately 49.5 percent.

In addition, Enserco Energy, Inc., our gas marketing unit, has a $135 million uncommitted, discretionary line of credit to provide credit support for the purchase of natural gas. As of December 31, 2003, we had a $3.0 million guarantee to the lender under this facility. At December 31, 2003, there were outstanding letters of credit issued under the facility of $80.3 million with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc. (BHER), our crude oil marketing unit, had a $25 million uncommitted, discretionary credit facility at December 31, 2003. The facility allows BHER to elect up to $40 million of available credit via notification to the bank at the beginning of each calendar quarter. This line of credit provides credit support for the purchases of crude oil by BHER. We provided no guarantee to the lender under this facility. At December 31, 2003, BHER had letters of credit outstanding of $7.9 million and no borrowing balance outstanding on its overdraft line.

Our ability to obtain additional financing, if necessary, will depend upon a number of factors, including our future performance and financial results, and capital market conditions. We cannot assure you that we will be able to raise additional capital on reasonable terms or at all.

The following information is provided to summarize our cash obligations and commercial commitments.

Contractual Obligations	Payments Due by Period (in thousands) Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt (a)	$ 886,118	$17,659	$259,497	$136,744	$472,218
Operating lease obligations (b)	14,161	1,593	3,854	1,784	6,930
Capital leases (c)	56	26	30	--	--
Unconditional purchase obligations (d)	245,661	23,471	68,213	36,076	117,901
Other long-term obligations (e)	22,985	--	--	--	22,985
Total contractual cash obligations	$ 1,168,981	$42,749	$331,594	$174,604	$620,034

(a) In addition the following amounts are required for interest payments on long-term debt over the next five years: $42.7 million in 2004, $42.2 million in 2005, $39.2 million in 2006, $35.0 million in 2007 and $33.1 million in 2008.

(b) Includes operating leases associated with several office buildings and land leases associated with the Araphoe, Valmont, Harbor and Ontario power plants.

(c) Represents a lease on computer hardware.

(d) Unconditional purchase obligations include the capacity costs associated with our purchase power agreement with PacifiCorp and certain transmission, communication, gas purchase and gas transportation agreements. The energy charge under the purchase power agreement and the commodity price under the gas purchase contract are variable costs, which for purposes of estimating our future obligations, were calculated using existing prices at December 31, 2003. Our utility's transmission obligations are based on filed tariffs as of December 31, 2003. Transmission obligations with Nevada Power are based on estimates of final tariffs currently under negotiation. Actual future costs under the variable rate contracts may differ materially from the estimates used in the above table.

(e) Includes our asset retirement obligations associated with our oil and gas and mining segments as discussed in Note 1 to our Notes to Consolidated Financial Statements.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2003, we had guarantees totaling $192.1 million in place. Of the $192.1 million, $144.3 million was related to guarantees associated with subsidiaries' debt to third parties, which is recorded as liabilities on the Consolidated Balance Sheets, $18.3 million was related to performance obligations under subsidiary contracts and $29.5 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 5 of our Notes to Consolidated Financial Statements.

As of December 31, 2003, we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2003	Year Expiring
Guarantee payments under the Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee payments under certain energy marketing derivative, power and gas agreements	2,500	2004
Guarantee of certain obligations under Enserco's credit facility	3,000	2004
Guarantee performance of Black Hills Wyoming under a power sales agreement	5,000	2004
Guarantee of obligation of Las Vegas Cogeneration II under an interconnection and operation agreement	750	2005
Guarantee obligations under the Wygen Plant Lease	111,100	2008
Guarantee payment and performance under credit agreements for two combustion turbines	30,214	2010
Indemnification for subsidiary reclamation/surety bonds	29,488	Ongoing
	$192,052	

Credit Ratings

As of February 29, 2004, our issuer credit rating is “Baa3” by Moody’s Investors Service and our corporate credit rating is “BBB-” by Standard & Poor’s. In addition, our utility’s first mortgage bonds are rated “Baa1” and “BBB” by Moody’s and Standard & Poor’s, respectively. Standard & Poor’s downgraded our issuer credit rating to “BBB-” in May 2003. This credit rating downgrade had minimal effect on our interest rates under our credit agreements. These security ratings are subject to revision and/or withdrawal at any time by the respective rating organizations. None of our current credit agreements contain acceleration triggers. If our credit ratings drop below investment grade, however, pricing under the credit agreements would be affected. Based upon borrowings outstanding at December 31, 2003, a further credit downgrade to BB+ would increase interest expense by approximately $1.5 million a year.

Capital Requirements

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

	2003	2002	2001
	(in thousands)		
Property additions and acquisition costs:			
Wholesale energy	$ 81,271	$ 249,683	$ 532,774
Electric utility	25,427	31,251	41,313
Communications and other	9,993	22,984	20,055
Common stock dividends	37,025	31,116	28,517
Maturities/redemptions of long-term debt	139,310	32,527	13,960
	$ 293,026	$ 367,561	$ 636,619

Our capital additions for 2003 were $116.7 million. The capital expenditures were primarily for maintenance capital, development drilling and the completion of the construction of an AC-DC-AC converter station for our electric utility.

Our capital additions for 2002 were $303.9 million. The major capital items for the year included the following:

- Acquisition of additional assets and interests in crude oil pipelines and storage facilities.
- Continuation of the construction of our 224 megawatt gas-fired Las Vegas II power plant located near Las Vegas, Nevada, which was placed into service in January 2003.
- Completion of construction of the 50 megawatt combined-cycle expansion at our Arapahoe site in Denver, Colorado, which was placed into service in October 2002.
- Acquisition of an additional 30 percent interest in the Harbor Cogeneration facility.
- Acquisitions of various interests in partnerships in which we previously held a majority interest.
- Completion of construction of the Lange Combustion Turbine for our electric utility, which was placed into service in March 2002.
- Construction of an AC-DC-AC Converter Station for our electric utility, which was placed into service in the fourth quarter of 2003.
- Continuation of the construction of our communications fiber optic network.

Our capital additions for 2001 were $594.1 million. The major capital items for the year included the following:

- Acquisition of the 240 megawatt Fountain Valley gas-fired turbine generation facility located near Colorado Springs, Colorado which was placed in service in third quarter 2001.
- Acquisition of the 277 megawatt gas-fired co-generation power plant project located near Las Vegas, Nevada, of which 53 megawatts were operational and 224 megawatts were placed in service in January 2003.
- Construction of the 50 megawatt combined-cycle expansion at our Arapahoe site in Denver, Colorado, which was placed in service in October 2002.
- Completion of construction of the 40 megawatt gas-turbine expansion at our Valmont, Colorado site, which was placed in service in July 2001.
- Completion of construction of the 40 megawatt gas-fired combustion turbine unit at our Wyodak site, which we placed in service in May 2001.
- Completion of the 18 megawatt combined-cycle upgrade of the Harbor facility near Long Beach, California.
- Acquisitions of various interests in partnerships in which we previously held a minority interest.
- Acquisition of operating and non-operating interests in 74 gas and oil wells from Stewart Petroleum Corporation.
- Construction of a 40 megawatt gas-fired turbine known as the Lange project, which was placed in service in early 2002.
- Construction of our communications fiber optic network.

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

	2004	2005	2006
		(in thousands)	
Wholesale energy	$ 72,010	$ 43,740	$ 46,770
Electric utility	25,879	30,040	16,890
Communications	8,840	4,930	4,200
Corporate	5,540	--	--
Development capital	200,000	200,000	200,000
	$ 312,269	$ 278,710	$ 267,860

We expect to finance any development capital spent on power generating facilities primarily with long-term, non-recourse project level debt. We expect that any project-level debt will contain significant restrictions on distributions of cash from the project to us.

Market Risk Disclosures

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

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

- commodity price risk associated with our marketing businesses, our natural length in crude oil and natural gas production, and fuel procurement for our gas fired generation assets; and

- interest rate risk associated with our variable rate credit facilities and our project financing floating rate debt as described in Notes 10 and 11 of our Notes to Consolidated Financial Statements.

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 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 (BHCRPP)*. These policies have been approved by our Board of Directors and are routinely reviewed by our Audit Committee. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. We have a formalized Executive Risk Committee composed of senior level executives that meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Trading Activities

<u>Natural Gas Marketing</u>

We have a natural gas marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in the Western and Mid-continent regions of the United States and Canada. For producer services our main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchases, scheduling services, imbalance management, risk management services and transportation management. We accomplish this goal through industry experience, extensive contacts, transportation and risk management expertise, trading skills and personal attention. Our origination efforts focus on supplying and providing electricity generators 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 third party natural gas. These functions are predominately value-added services and rely on our ability to execute storage and transportation arbitrage opportunities.

To effectively manage our producer services', end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial instruments including over-the-counter swaps and options and storage and transportation agreements.

We conduct our gas marketing business activities within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, we permit only limited market risk positions as clearly defined in these policies and procedures. Therefore, substantially all of our marketing positions are fully hedged. We attempt to balance our portfolio in terms of volume and timing of performance and delivery obligations.

Monitoring and Reporting Market Risk Exposures

Senior management uses a number of quantitative tools to measure, monitor, and limit our exposure to market risk in our natural gas portfolio. We measure and monitor the market risk inherent in the natural gas trading portfolio employing value-at-risk (VaR) analysis and scenario analysis. VaR is a statistical measure that quantifies the probability and magnitude of potential future losses related to open contract positions. We use scenario analysis to test the impact of extreme moves in both specific delivery points and overall commodity prices on our portfolio value. We also monitor and limit our market risk by establishing limits on the nominal size of positions based on trader, location, and market.

VaR is a statistical measure used to quantify the potential loss in fair value of the trading portfolio over a particular time, with a specified likelihood of occurrence, due to adverse market price changes. We use an external VaR model from a third party vendor and utilize independent commodity pricing data. The modeling of VaR involves a number of assumptions and approximations. Inputs for the VaR calculation include commodity prices, positions, instrument valuations, and variance-covariance matrices. While we believe that our assumptions and approximations are reasonable, there is currently no uniform methodology or best practice for calculating VaR in the energy sector.

We calculate VaR on a daily basis to determine the potential three-day favorable and unfavorable changes to the market value of our portfolio. The VaR is computed utilizing Monte Carlo simulation based on correlation matrices for price movements over a specified period (generally ranging from one to three months) to simulate forward price curves in the natural gas markets to estimate the “worst case” outcomes on the existing portfolio value. The VaR computations utilize a 99 percent confidence level for the resultant price movement and the holding period specified for the calculation. This calculation means that there is a one in one hundred (1 in 100) statistical chance that the portfolio value will fall below the expected maximum potential reduction in portfolio value at least as large as the reported VaR over a three day period, provided that no mitigation actions are taken during these three days.

At year-end 2003, we were implementing an enhanced trade capture system and due to technical constraints, must estimate our VaR. Our estimate of the three-day, 99 percent confidence level VaR is less than $2.0 million. During this system implementation, risk management activities focused upon scrutinizing positions, their changes in daily mark-to-market and other non-statistical risk management techniques.

Actual commodity price volatility can result in portfolio values worse than predicted using the VaR model. The VaR methodology assumes a normal distribution of price changes; thus, if the actual distribution is not normal, the VaR may understate actual results. VaR is used to estimate the risk of the entire gas marketing portfolio. For locations that have insufficient daily trading activity, VaR may not accurately estimate risk due to limited price information. Therefore, stress tests are employed, in addition to VaR, to further measure risk when market price information may prove insufficient. VaR is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of VaR is that past changes in assumed market risk factors may not produce accurate predictions of future market risk. VaR should be evaluated in light of this and the methodology’s other limitations.

The contract or notional amounts, terms and mark-to-market values of our natural gas marketing and derivative commodity instruments at December 31, 2003 and 2002, are set forth in Note 2 of our Notes to Consolidated Financial Statements.

The following table provides a reconciliation of the activity in energy trading contracts marked to market during the year ended December 31, 2003 (in thousands):

Total fair value of natural gas marketing contract net assets at December 31, 2002	$ 3,021
Net cash settled during the year on contracts that existed at December 31, 2002	(682)
Change in fair value due to change in techniques and assumptions(a)	(6,631)
Unrealized gain on new contracts entered during the year and still existing at December 31, 2003	1,375
Realized gain on contracts that existed at December 31, 2002 and were settled during year	2,551
Unrealized loss on contracts that existed at December 31, 2002 and still exist at December 31, 2003	(42)
Total fair value of natural gas marketing contract net assets at December 31, 2003	$ (408)

(a) This amount reflects the gross fair value adjustment recorded for the adoption of EITF 02-3, as further described in Note 1 of our Notes to Consolidated Financial Statements.

At December 31, 2003, we had a mark to fair value unrealized loss of $0.4 million for our natural gas marketing activities. Of this amount, $0.1 million was current and $0.3 million was non-current. The source of fair value measurements were as follows (in thousands):

	Maturities		
Source of Fair Value	**2004**	**2005 and Thereafter**	**Total Fair Value**
Actively quoted (i.e., exchange-traded) prices	$ 615	$ (121)	$ 494
Prices provided by other external sources	(732)	(170)	(902)
Modeled	--	--	--
Total	$ (117)	$ (291)	$ (408)

Activities Other than Trading

Crude Oil Marketing

We have a crude oil marketing and transportation services company operating predominately in Texas, Oklahoma, and Louisiana. We specialize in providing independent producers with marketing and transportation services necessary to market their crude oil production to end-use markets. Our main objective is to provide value in the supply chain by acting as the producer’s “marketing arm” for wellhead purchasing, scheduling services, imbalance management and transportation management.

To provide these services, we execute forward physical crude oil purchase contracts with producers and resell into various crude oil markets. Through these transactions, we effectively lock in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. We do not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that we identify will be managed and mitigated within the guidelines stipulated in the BHCRPP.

The contract or notional amounts, terms and mark-to-market values of our crude oil contracts at December 31, 2003 and 2002 are set forth in Note 2 of our Notes to Consolidated Financial Statements.

Oil and Gas Exploration and Production

We produce natural gas and crude oil through our exploration and production activities. These 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 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, are administered by the Executive Risk Committee and are routinely reviewed by our Audit Committee.

Any hedging strategies are conducted with an enterprise wide perspective. As more fully defined in the next section, we have some fuel procurement risk within our gas-fired generation business. Therefore, hedging in the oil and gas segment considers any natural hedge offsets in the power generation segment. In certain cases, we do not hedge forecasted natural gas production when we have offsetting market risk in our fuel requirements in the power generation segment. In other words, exploration and production’s natural length is used to offset generation’s short position.

The contract or notional amounts, terms and fair values of our contracts used to hedge portions of our crude oil and natural gas production at December 31, 2003 and 2002 are set forth in Note 2 of our Notes to Consolidated Financial Statements.

To mitigate commodity price risk and preserve cash flows, we use over-the-counter swaps and options.

Power Generation

We have a portfolio of gas-fired fueled generation assets located throughout several Western states. The output from most of these generation assets are sold under long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some gas-fired generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is our policy that fuel risk, to the extent possible, be hedged. Since we are “long” natural gas in our exploration and production segment, we look at our enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, we may attempt to hedge only enterprise wide “long” or “short” positions.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

We engage in activities to manage risks associated with changes in interest rates. We have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. At December 31, 2003, we had $138.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of three years. Further details of the swap agreements are set forth in Note 2 of our Notes to Consolidated Financial Statements.

On December 31, 2003 and 2002, our interest rate swaps and related balances were as follows (in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)
December 31, 2003								
Swaps on project financing	$113,000	4.48%	2.75	$ 256	$ --	$3,247	$ 1,931	$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	--	--	169	--	(169)
	$138,000			$ 256	$ --	$3,416	$ 1,931	$ (5,091)
December 31, 2002								
Swaps on project financing (a)	$147,000	4.98%	4	$ --	$ --	$5,104	$ 2,314	$ (7,418)
Swaps on corporate debt	25,000	5.28%	1	--	--	947	166	(1,113)
	$172,000			$ --	$ --	$6,051	$ 2,480	$ (8,531)

(a) Amounts exclude interest rate swaps related to our discontinued hydroelectric operations, sold in September 2003. At December 31, 2002, these swaps had a notional amount of $65.3 million and a fair value of $(9.8) million. The related balances are currently classified in “discontinued operations”.

We anticipate a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2004. Based on December 31, 2003 market interest rates, $3.2 million will be realized as additional interest expense during 2004. Estimated and realized amounts will likely change during 2004 as market interest rates change.

At December 31, 2003, we had $424.3 million of outstanding, variable-rate debt of which $286.3 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause interest expense to increase $2.9 million.

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

	2004	2005	2006	2007	2008	Thereafter	Total
Cash equivalents							
Fixed rate	$172,771	$ --	$ --	$ --	$ --	$ --	$172,771
Long-term debt							
Fixed rate	$ 2,845	$ 2,854	$ 2,865	$ 2,049	$ 2,062	$449,149	$461,824
Average interest rate	8.5%	8.5%	8.5%	9.6%	9.6%	7.1%	7.2%
Variable rate (a)	$ 14,814	$15,504	$238,274	$113,468	$19,165	$ 23,069	$424,294
Average interest rate	2.7%	2.7%	2.2%	2.7%	1.7%	3.1%	2.4%
Total long-term debt	$ 17,659	$18,358	$241,139	$115,517	$21,227	$472,218	$886,118
Average interest rate	3.7%	3.6%	2.2%	2.8%	2.5%	6.9%	4.9%

(a) Approximately 32.5 percent of the variable rate long-term debt has been hedged with interest rate swaps moving the floating rates to fixed rates with an average interest rate of 4.62 percent.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy (BHCCP) that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, we have a formalized Executive Credit Committee composed of senior executives that meets on a regular basis to review the Company's credit activities and to ensure that these activities are conducted within the policies adopted by the Company.

For our energy marketing, production, and generation activities, we attempt 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 asset 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 guarantee that we will continue to experience the same credit loss rates that we have in the past or that an investment grade counterparty will not default sometime in the future.

At the end of the year, our credit exposure (exclusive of regulated utility retail customers and communications) was concentrated with investment grade companies. Approximately 63 percent of our credit exposure was with investment grade companies. For the 37 percent credit exposure with non-investment grade rated counterparties, approximately 55 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

Rate Regulation

Existing Rate Regulation

In June 1999, the South Dakota Public Utilities Commission approved a settlement, which extended a rate freeze in effect since 1995 until January 1, 2005.

The South Dakota settlement provides that, absent an extraordinary event, we may not file for any increase in our rates or invoke any fuel and purchased power adjustment tariff which would take effect during the freeze period. The specified extraordinary events are:

- new governmental impositions increasing annual costs for South Dakota customers by more than $2.0 million;
- simultaneous forced outages of both our Wyodak plant and Neil Simpson II plant projected to continue at least 60 days;
- forced outages occurring to either plant which continue for a period of three months and are projected to last at least nine months;
- an increase in the Consumer Price Index at a monthly rate for six months which would result in a 10 percent or higher annual inflation rate;
- the loss of a South Dakota customer or revenue from an existing South Dakota customer that would result in a loss of revenue of $2.0 million or more during any 12-month period;
- the cost of coal to our South Dakota customers increases and is projected to increase by more than $2.0 million over the cost for the most recent calendar year; and
- electric deregulation occurs as a result of either federal or state mandate, which allows any of our customers to choose its provider of electricity at any time during the freeze period.

During the freeze period, except as identified above, we are undertaking the risks of:

- machinery failure;
- load loss caused by either an economic downturn or changes in regulation;
- increased costs under power purchase contracts over which we have no control;
- government interferences; and
- acts of nature and other unexpected events that could cause material losses of income or increases in costs of doing business.

However, the settlement anticipates that we will retain, during that period of time, earnings realized from more efficient operations, sales from load growth, and off-system sales of power and energy.

Over the last several years, we have initiated an effort to enter into new contracts with our largest industrial customers. The new contracts contain "meet or release" provisions that grant us a five-year right to continue to serve a customer at market rates in the event of deregulation. Additionally, through our General Service Large Optional Combined Account Billing Tariff, we have allowed general service customers to aggregate their loads. This tariff also provides us with a five-year right to continue to serve those customers in the event of deregulation. Our "meet or release" contracts currently total more than 108 megawatts of large commercial and industrial load. These contracts provide us the assurance of a firm local market for our power resources, in the event deregulation occurs. These industrial and large commercial customers, together with our wholesale power sale agreements with the City of Gillette, Wyoming and Montana-Dakota Utilities Company, equal approximately 47 percent of our utility's firm load.

Regulatory Accounting

As it pertains to the accounting for our utility operations, we follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and our financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions in which we operate. As a result of our regulatory activity, a 50-year depreciable life for the Neil Simpson II plant is used for financial reporting purposes. If we were not following SFAS 71, a 35- to 40-year life would probably be more appropriate, which would increase depreciation expense by approximately $0.6 — $1.1 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to our generation operations. In the event we determine that we no longer meet the criteria for following SFAS 71, the accounting impact to us could be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that may give rise to the discontinuance of SFAS 71 include increasing competition that could restrict our ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. We periodically review these criteria to ensure that the continuing application of SFAS 71 is appropriate.

New Accounting Pronouncements

See Note 1 of our Notes to Consolidated Financial Statements for information on new accounting standards adopted in 2003 or pending adoption.

Safe Harbor for Forward Looking Information

This Annual Report on Form 10-K includes "forward-looking statements" as defined by the Securities and Exchange Commission, or SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including the risk factors described in Item 1 of this Form 10-K and the following:

- Our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- General economic and political conditions, including tax rates or policies and inflation rates;
- Our use of derivative financial instruments to hedge commodity and interest rate risks;
- The creditworthiness of counterparties to trading and other transactions, and defaults on amounts due from counterparties;
- The amount of collateral required to be posted from time to time in our transactions;
- Changes in or compliance with laws and regulations, particularly those relating to taxation, safety and protection of the environment;
- The timing and extent of changes in energy-related and commodity prices, interest rates, energy and commodity supply or volume, the cost of transportation of commodities, and demand for our services, all of which can affect our earnings, liquidity position and the underlying value of our assets;
- Weather and other natural phenomena;
- The timing of production from oil and gas development facilities, which may be dependent upon issuance by federal, state, and tribal governments, or agencies thereof, of building, environmental and other permits, and the availability of specialized contractors, work force, equipment, and prices of and demand for our products;
- The extent of success in connecting natural gas supplies to gathering and processing systems;
- Industry and market changes, including the impact of consolidations and changes in competition;
- The effect of accounting policies issued periodically by accounting standard-setting bodies;
- The cost and effects on our business, including insurance, resulting from terrorist actions or responses to such actions;
- Capital market conditions, including price risk due to marketable securities held as investments in benefit plans; and
- Other factors discussed from time to time in our filings with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events, or otherwise.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

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 (the Corporation) and subsidiaries as of December 31, 2003 and 2002, 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, 2003. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Corporation adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* and Emerging Issues Task Force 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities*, and effective December 31, 2003, the Corporation adopted Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities*, as discussed in Note 1 to the consolidated financial statements effective January 1, 2002, the Corporation adopted Statement of Financial Accounting Standards No. 142 *Goodwill and Other Intangible Assets*.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2004

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2003	2002	2001
	(in thousands, except per share amounts)		
Revenues:			
Operating revenues	$ 1,136,052	$ 908,491	$ 737,827
Contract termination revenue	114,000	--	--
	1,250,052	908,491	737,827
Operating expenses:			
Fuel and purchased power	718,450	580,973	382,909
Operations and maintenance	99,339	68,259	69,644
Administrative and general	73,690	65,017	73,779
Depreciation, depletion and amortization	80,791	63,865	48,039
Taxes, other than income taxes	29,565	18,026	22,422
Impairment of long-lived assets	117,207	--	--
	1,119,042	796,140	596,793
Equity in earnings of unconsolidated subsidiaries	5,747	4,588	14,331
Operating income	136,757	116,939	155,365
Other income (expense):			
Interest expense	(52,579)	(33,564)	(30,475)
Interest income	1,076	610	2,080
Other expense	(539)	(554)	(4,759)
Other income	2,200	4,332	12,051
	(49,842)	(29,176)	(21,103)
Income from continuing operations before minority interest, income taxes and change in accounting principle	86,915	87,763	134,262
Minority interest	--	(2,277)	(2,041)
Income taxes	(29,920)	(26,907)	(48,110)
Income from continuing operations before changes in accounting principles	56,995	58,579	84,111
Income from discontinued operations, net of taxes	9,422	1,977	3,966
Changes in accounting principles, net of taxes	(5,195)	896	--
Net income	61,222	61,452	88,077
Preferred stock dividends	(258)	(223)	(527)
Net income available for common stock	$ 60,964	$ 61,229	$ 87,550
Earnings per share of common stock:			
Basic-			
Continuing operations	$ 1.86	$ 2.18	$ 3.29
Discontinued operations	0.31	0.07	0.16
Changes in accounting principles	(0.17)	0.03	--
Total	$ 2.00	$ 2.28	$ 3.45
Diluted-			
Continuing operations	$ 1.84	$ 2.16	$ 3.27
Discontinued operations	0.30	0.07	0.15
Changes in accounting principles	(0.17)	0.03	--
Total	$ 1.97	$ 2.26	$ 3.42
Weighted average common shares outstanding:			
Basic	30,496	26,803	25,374
Diluted	31,015	27,167	25,771

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

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

At December 31,	2003	2002
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 172,771	$ 75,045
Restricted cash	1,350	1,070
Accounts receivable (net of allowance for doubtful accounts of $7,345 and $3,226, respectively)	201,992	167,567
Notes receivable	554	34,085
Materials, supplies and fuel	44,895	24,139
Derivative assets	26,804	36,393
Prepaid income taxes	18,940	--
Deferred income taxes	4,229	6,006
Other current assets	8,324	7,311
Assets of discontinued operations	3,893	178,468
	483,752	530,084
Investments	27,347	18,707
Property, plant and equipment	1,882,697	1,703,372
Less accumulated depreciation and depletion	(440,275)	(377,568)
	1,442,422	1,325,804
Other assets:		
Derivative assets	1,002	2,406
Goodwill	30,144	23,913
Intangible assets, net	40,070	78,089
Other	38,488	20,971
	109,704	125,379
	$ 2,063,225	$ 1,999,974
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 162,722	$ 168,250
Accrued income taxes	5,816	2,096
Accrued liabilities	66,629	51,046
Current maturities of long-term debt	17,659	15,324
Notes payable	--	340,500
Derivative liabilities	32,967	42,316
Liabilities of discontinued operations	467	106,954
	286,260	726,486
Long-term debt, net of current maturities	868,459	540,958
Deferred credits and other liabilities:		
Deferred income taxes	125,041	132,645
Derivative liabilities	3,247	2,889
Other	65,782	61,833
	194,070	197,367
Minority interest	4,689	--
Commitments and contingencies (Notes 5, 11, 14 and 15)		
Stockholders' equity:		
Preferred stock	8,143	5,549
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 32,447,765 shares in 2003 and 27,102,351 shares in 2002	32,448	27,102
Additional paid-in capital	379,271	246,997
Retained earnings	304,567	280,628
Treasury stock at cost - 150,048 shares in 2003 and 169,724 shares in 2002	(3,560)	(3,921)
Accumulated other comprehensive loss	(11,122)	(21,192)
	701,604	529,614

Total stockholders' equity	709,747	535,163
	$ 2,063,225	$ 1,999,974

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

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2003	2002	2001
		(in thousands)	
Operating activities:			
Net income available for common	$ 60,964	$ 61,229	$ 87,550
Adjustments to reconcile net income available for common to net cash provided by operating activities-			
Income from discontinued operations	(9,422)	(1,977)	(3,966)
Depreciation, depletion and amortization	80,791	63,865	48,039
Impairment of long-lived assets	117,207	--	--
Issuance of treasury stock for operating expense	361	2,252	4,243
Provision for valuation allowances	3,363	(2,935)	9,632
Net change in derivative assets and liabilities	(317)	(2,086)	(6,377)
Deferred income taxes	(3,680)	33,457	15,555
Undistributed earnings in associated companies	(3,874)	(2,972)	(9,287)
Minority interest	--	2,277	2,041
Accounting changes	5,195	(896)	--
Change in operating assets and liabilities-			
Accounts receivable and other current assets	(75,045)	(61,357)	172,036
Accounts payable and other current liabilities	(10,605)	113,895	(157,360)
Other operating activities	5,631	4,099	2,131
	170,569	208,851	164,237
Investing activities:			
Property, plant and equipment additions	(90,353)	(231,693)	(373,982)
Proceeds from sale of assets	185,926	--	--
Payment for acquisition of net assets, net of cash acquired	--	(23,229)	(199,001)
Payment for acquisition of minority interest	(9,000)	(13,800)	(16,676)
Increase in notes receivable - Mallon Resources	(5,164)	(33,815)	--
Other investing activities	(3,566)	(1,870)	3,258
	77,843	(304,407)	(586,401)
Financing activities:			
Dividends paid on common stock	(37,025)	(31,116)	(28,517)
Common stock issued	123,073	5,084	168,522
Increase (decrease) in short-term borrowings, net	(340,500)	(19,500)	149,000
Long-term debt - issuance	252,000	223,135	144,610
Long-term debt - repayments	(139,310)	(25,069)	(7,176)
Other financing activities	(8,924)	(8,312)	321
	(150,686)	144,222	426,760
Increase in cash and cash equivalents	97,726	48,666	4,596
Cash and cash equivalents:			
Beginning of year	75,045	26,379	21,783
End of year	$ 172,771	$ 75,045	$ 26,379
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 51,452	$ 41,404	$ 39,563
Income taxes paid (refunded)	$ 58,660	$ (31,353)	$ 40,374
Non-cash net assets acquired through issuance of common and preferred stock (Note 14)	$ 6,231	$ 3,826	$ 3,628
Property, plant and equipment acquired with accrued liabilities and the issuance of long-term debt	$ 6,951	$ --	$ --
Non-cash net assets of Mallon Resources, acquired through issuance of common stock and decrease in notes receivable (Note 19)	$ 51,153	$ --	$ --

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

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

	Common Stock		Additional		Treasury Stock		Accumulated Other	
	Shares	Amount	Paid-In Capital	Retained Earnings	Shares	Amount	Comprehensive Income (loss)	Total
	(in thousands)							
Balance at December 31, 2000	23,302	$23,302	$ 73,442	$191,482	381	$(9,067)	$ (813)	$278,346
Comprehensive Income:								
Net income	--	--	--	88,077	--	--	--	88,077
Other comprehensive loss, net of tax (see Note 16)	--	--	--	--	--	--	(2,929)	(2,929)
Total comprehensive income	--	--	--	88,077	--	--	(2,929)	85,148
Dividends on preferred stock	--	--	--	(527)	--	--	--	(527)
Dividends on common stock	--	--	--	(28,517)	--	--	--	(28,517)
Issuance of common stock	3,589	3,589	167,012	--	--	--	--	170,601
Treasury stock issued, net	--	--	1,000	--	(142)	3,564	--	4,564
Balance at December 31, 2001	26,891	26,891	241,454	250,515	239	(5,503)	(3,742)	509,615
Comprehensive Income:								
Net income	--	--	--	61,452	--	--	--	61,452
Other comprehensive loss, net of tax (see Note 16)	--	--	--	--	--	--	(17,450)	(17,450)
Total comprehensive income	--	--	--	61,452	--	--	(17,450)	44,002
Dividends on preferred stock	--	--	--	(223)	--	--	--	(223)
Dividends on common stock	--	--	--	(31,116)	--	--	--	(31,116)
Issuance of common stock	211	211	4,993	--	--	--	--	5,204
Treasury stock issued, net	--	--	550	--	(70)	1,582	--	2,132
Balance at December 31, 2002	27,102	27,102	246,997	280,628	169	(3,921)	(21,192)	529,614
Comprehensive Income:								
Net income	--	--	--	61,222	--	--	--	61,222
Other comprehensive income, net of tax (see Note 16)	--	--	--	--	--	--	10,070	10,070
Total comprehensive income	--	--	--	61,222	--	--	10,070	71,292
Dividends on preferred stock	--	--	--	(258)	--	--	--	(258)
Dividends on common stock	--	--	--	(37,025)	--	--	--	(37,025)
Issuance of common stock	5,346	5,346	130,484	--	--	--	--	135,830
Treasury stock issued, net	--	--	1,790	--	(19)	361	--	2,151
Balance at December 31, 2003	32,448	$32,448	$379,271	$304,567	150	$(3,560)	$(11,122)	$701,604

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

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation and its subsidiaries operate in three primary operating groups: non-regulated wholesale energy, regulated electric utility and communications. The Company operates its wholesale energy businesses through its direct and indirect subsidiaries: Wyodak Resources related to coal, Black Hills Exploration and Production related to oil and natural gas, Enserco Energy and Black Hills Energy Resources related to fuel marketing of natural gas and oil and oil transportation, respectively, and Black Hills Generation and its subsidiaries and Black Hills Wyoming related to independent power activities, all aggregated for reporting purposes as Black Hills Energy; operates its public utility electric operations through its subsidiary, Black Hills Power, Inc.; and operates its communications operations through its subsidiaries Black Hills Fiber Systems, Black Hills FiberCom L.L.C. and Daksoft. For further descriptions of the Company's business segments, see Note 18.

In 2003, the Company sold its hydroelectric power plants located in Upstate New York. The non-strategic assets were sold effective September 30, 2003. In 2002, the Company sold its coal marketing business. The non-strategic assets were sold effective August 1, 2002.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to allowance for uncollectible accounts receivable, inventory obsolescence, realization of market value of derivatives due to commodity risk, intangible asset valuations and useful lives, long-lived asset values and useful lives, proved oil and gas reserve volumes, employee benefit plans, environmental accruals and contingencies. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly owned and majority-owned subsidiaries. In addition, as of December 31, 2003, the Company consolidated the financial information of Wygen Funding, Limited Partnership, a variable interest entity in which the Company is the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). Generally, the Company uses equity accounting for investments of which it owns between 20 and 50 percent and investments in partnerships under 20 percent if the Company exercises significant influence.

All significant intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with intercompany fuel sales in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Total intercompany fuel sales not eliminated were $10.3 million, $10.5 million and $11.2 million in 2003, 2002 and 2001, respectively.

The Company owns 51 percent of the voting securities of Black Hills FiberCom, LLC (FiberCom). During 2000, FiberCom's operating losses reduced its unaffiliated members' equity below zero. At that point, the Company began to fund all operations and recognize 100 percent of FiberCom's net losses and will continue to do so until such time as additional equity investments are made by third parties or future net income restores members' equity to a positive amount.

As discussed in Note 19, the Company and its subsidiaries made several acquisitions during 2003 and 2002. The Company's consolidated statements of income include operating activity of these companies beginning with their acquisition date.

The Company uses the proportionate consolidation method to account for its working interests in oil and gas properties and for its ownership in the jointly owned Black Hills Power transmission tie and the Wyodak power plant as discussed in Note 13.

Minority Interest in Subsidiaries

Minority interest in the accompanying Consolidated Statements of Income represents the share of income or loss of certain consolidated subsidiaries attributable to the minority shareholders of those subsidiaries. The minority interest in the accompanying Consolidated Balance Sheets reflect the amount of the underlying net assets of those certain consolidated subsidiaries attributable to the minority shareholders in those subsidiaries.

Earnings attributable to minority ownership in certain subsidiaries are generally shown on the accompanying consolidated statement of income on a pre-tax basis as the subsidiaries with minority investors are typically limited liability companies or partnerships which pay no tax at the corporate or partnership level.

Regulatory Accounting

The Company’s subsidiary, Black Hills Power, 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 Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company’s non-regulated businesses.

Black Hills Power follows the provisions of SFAS 71, and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating Black Hills Power. A 50-year depreciable life for the Neil Simpson II plant is used for financial reporting purposes. If Black Hills Power were not a regulated utility following SFAS 71, a 35 to 40 year life would likely be more appropriate, which would increase depreciation expense by $0.6 — $1.1 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to Black Hills Power’s generation operations. In the event Black Hills Power determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company could be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict Black Hills Power’s ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure that the continuing application of SFAS 71 is appropriate.

At December 31, 2003 and 2002, the Company had regulatory assets of $4.3 million and $4.4 million and regulatory liabilities of $6.3 million and $6.8 million, respectively. Regulatory assets are primarily recorded for the probable future revenue to recover future income taxes related to the deferred tax liability for the equity component of allowance for funds used during construction of utility assets. Regulatory liabilities include the probable future decrease in rate revenues related to a decrease in deferred tax liabilities for prior reductions in statutory federal income tax rates and also the cost of removal for utility plant, recovered through the Company’s electric utility rates. The regulatory assets are included in Other assets and the regulatory liabilities are included in Other deferred credits and other liabilities on the Consolidated Balance Sheets.

Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Notes Receivable

At December 31, 2002, the Company had a $33.8 million note receivable from Mallon Resources Corporation (Mallon). The Company entered into the note with Mallon as a result of entering into a definitive merger agreement to acquire Mallon in a stock-for-stock transaction. Upon completion of the Mallon acquisition on March 10, 2003, the note became an intercompany balance and eliminated in consolidation of the financial statements. As a result, the December 31, 2003 balance is $0. See Note 19 for additional information.

Materials, Supplies and Fuel

As of December 31, 2003, all materials, supplies and fuel are stated at the lower of cost or market on a first-in, first-out basis. The amounts by major classification are provided as follows as of December 31:

Major Classification	2003	2002
	(in thousands)	
Materials and supplies	$ 18,920	$ 16,011
Fuel for generation	1,581	2,073
Gas and oil held by energy marketing	24,394	6,055
Total materials, supplies and fuel	$ 44,895	$ 24,139

During 2001, a provision of $1.4 million was charged to operations to write-down inventories at the Company's Communications group to estimated net realizable value.

Derivatives and Hedging Activities

The Company accounts for its derivative and hedging activities in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133 requires that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

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

Deferred Financing Costs

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

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is an allowance for funds used during construction (AFUDC) which represents the approximate composite cost of borrowed funds and a return on capital used to finance the project. The AFUDC was computed at an annual composite rate of 9.8 percent, 9.1 percent and 10.2 percent during 2003, 2002 and 2001, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $0.4 million, $11.5 million and $7.5 million in 2003, 2002 and 2001, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage, is charged to accumulated depreciation. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are computed on a straight-line basis. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method on volumes produced and estimated reserves.

Oil and Gas Operations

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a 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.

Under the full cost method, net capitalized costs are subject to a "ceiling test" which limits these costs to the present value of future net cash flows discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the net capitalized costs. Future net cash flows are estimated based on end-of-period spot market prices adjusted for contracted price changes. If the net capitalized costs exceed the full cost "ceiling" at period end, a permanent noncash write-down would be charged to earnings in that period unless subsequent market price changes eliminate or reduce the indicated write-down. Given the volatility of oil and gas prices, the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that a write-down of oil and gas properties could occur in the future. No "ceiling test" write-downs were recorded during 2003, 2002 or 2001.

Goodwill and Intangible Assets

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The amortization provisions of SFAS 142 apply to goodwill and intangible assets acquired after June 30, 2001. With respect to goodwill and intangible assets acquired prior to July 1, 2001, the Company was required to adopt SFAS 142 effective January 1, 2002. The cumulative effect adjustment recognized upon adoption of SFAS 142 was $0.1 million (after-tax), which had only a nominal impact on earnings per share. The adjustment consisted of income from the after-tax write-off of negative goodwill from prior acquisitions in our power generation segment of $0.9 million, offset by a $0.8 million after-tax write-off for the impairment of goodwill related to our discontinued coal marketing operations (see Note 20). The goodwill impairment was a result of changes in the criteria for the measurement of impairments from an undiscounted to a discounted cash flow method. If the carrying value exceeds the fair value, an impairment loss will be recognized. A discounted cash flow approach was used to determine fair value of the Company's businesses for the purposes of testing for impairment.

The pro forma effects of adopting SFAS 142 for the years ended December 31, 2003, 2002 and 2001 are as follows (in thousands, except per share amounts):

	2003	2002	2001
Net income as reported	$61,222	$ 61,452	$88,077
Cumulative effect of change in accounting principle, net of tax	--	(896)	--
Cumulative effect of change in accounting principle included in "Discontinued operations," net of tax	--	755	--
Income excluding cumulative effect of change in accounting principle	61,222	61,311	88,077
Add: goodwill amortization	--	--	1,499
Adjusted net income	$61,222	$ 61,311	$89,576

	2003	2002	2001
Basic earnings per share	$2.00	$ 2.28	$3.45
Change in accounting principle	--	(0.03)	--
Change in accounting principle included in discontinued operations	--	0.02	--
Add goodwill amortization	--	--	0.06
Adjusted basic earnings per share	$2.00	$ 2.27	$3.51
Diluted earnings per share	$1.97	$ 2.26	$3.42
Change in accounting principle	--	(0.03)	--
Change in accounting principle included in discontinued operations	--	0.02	--
Add goodwill amortization	--	--	0.06
Adjusted diluted earnings per share	$1.97	$ 2.25	$3.48

The substantial majority of the Company's goodwill and intangible assets are contained within the Power Generation segment. Changes to goodwill and intangible assets during the years ended December 31, 2003 and 2002, including the effects of adopting SFAS 142, but excluding $9.8 million of goodwill related to our hydroelectric plant assets classified into discontinued operations (Note 20), are as follows (in thousands):

	Goodwill	Amortized Other Intangible Assets
Balance at December 31, 2001, net of accumulated amortization	$ 18,921	$ 86,528
Change in accounting principle	1,492	--
Additions	3,826	9,640
Adjustments	(326)	(13,854)
Amortization expense	--	(4,225)
Balance at December 31, 2002, net of accumulated amortization	23,913	78,089
Additions	6,231	62
Impairment losses	--	(34,094)
Amortization expense	--	(3,987)
Balance at December 31, 2003, net of accumulated amortization	$ 30,144	$ 40,070

Intangible assets primarily relate to site development fees and above-market long-term contracts within the Power Generation segment and are amortized using a straight-line method using estimated useful lives ranging from 5 to 40 years. Intangible assets totaled $58.5 million, with accumulated amortization of $18.4 million at December 31, 2003 and $93.6 million, with accumulated amortization of $15.5 million at December 31, 2002. Amortization expense for intangible assets was $4.0 million, $4.2 million and $2.6 million in 2003, 2002 and 2001, respectively. Amortization expense for existing intangible assets for the next five years is expected to be approximately $3.3 million a year.

Intangible asset additions during the year ended December 31, 2002, were primarily the result of a $9.3 million addition related to purchase allocations in the acquisition of additional ownership interest in the Harbor Cogeneration Facility (see Note 19). This intangible asset primarily relates to an acquired ownership of additional interest in a contract termination payment stream at the facility.

During the third quarter of 2003, the Company wrote off intangible assets of $34.1 million, net of accumulated amortization of $1.1 million, related to the impairment of our Las Vegas II plant. The impairment charge is a result of a contract termination and subsequent impairment of the Las Vegas II plant (see Note 4).

Adjustments of intangible assets during the year ended December 31, 2002, primarily relate to final adjustments to the preliminary purchase price allocation of the Company's 2001 Las Vegas Cogeneration acquisition.

Goodwill additions during the years ended December 31, 2003 and 2002 were from contingent consideration related to the July 7, 2000 acquisition of Indeck Capital Inc. (see Note 14).

Impairment of Long-Lived Assets

The Company periodically evaluates whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of its long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, the Company would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, the Company would recognize an impairment loss. In 2003, a $117.2 million pre-tax impairment was recorded to reduce the carrying value of the Las Vegas II facility. In 2002, a $0.8 million pre-tax impairment was recorded for intangible assets in our discontinued coal marketing operations. No impairment loss was recorded during 2001.

Income Taxes

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

The Company uses the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. The Company classifies deferred tax assets and liabilities into current and noncurrent amounts based on the classification of the related assets and liabilities.

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured. Energy marketing businesses have historically used the mark-to-market method of accounting. Under that method, all energy marketing activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In accordance with Emerging Issues Task Force (EITF) Issue No. 02-3 “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” (EITF 02-3), all energy marketing contracts entered into after October 25, 2002 that do not meet the definition of derivatives as defined by SFAS 133, have been accounted for under the accrual method of accounting. For long-term non-utility power sales agreements revenue is recognized either in accordance with EITF No. 91-6, “Revenue Recognition of Long-Term Power Sales Contracts” (EITF 91-6), or in accordance with SFAS No. 13, “Accounting for Leases,” (SFAS 13) as appropriate. Under EITF 91-6, revenue is generally recognized as the lower of the amount billed or the average rate expected over the life of the agreement. Under SFAS 13, revenue is generally levelized over the life of the agreement. Revenues from one-year advertising contracts in telephone directories published by our Communications segment are recognized on the publication date with cash received prior to publication deferred until it is recognized. For its Investment in Associated Companies (see Note 6), which are involved in power generation, the Company uses the equity method to recognize as earnings its pro rata share of the net income or loss of the associated company.

Earnings Per Share of Common Stock

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

	2003		2002		2001	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$56,995		$58,579		$84,111	
Less: preferred stock dividends	(258)		(223)		(527)	
Basic - Income from continuing operations	56,737	30,496	58,356	26,803	83,584	25,374
Dilutive effect of:						
Stock options	--	102	--	91	--	223
Convertible preferred stock	258	222	223	148	527	148
Estimated contingent shares issuable for prior acquisition	--	158	--	88	--	--
Others	--	37	--	37	--	26
Diluted - Income from continuing operations	$56,995	31,015	$58,579	27,167	$84,111	25,771

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):

	2003	2002	2001
Options to purchase common stock	334	381	45
Restricted stock	21	34	12
	355	415	57

Stock-based Compensation

At December 31, 2003, the Company has three stock-based employee compensation plans under which it can issue stock options to its employees, which are described more fully in Note 8. The Company accounts for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123), to stock-based employee compensation as of December 31 (in thousands, except per share amounts):

	2003	2002	2001
Net income available for common stock, as reported	$ 60,964	$ 61,229	$ 87,550
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(794)	(990)	(705)
Pro forma net income	$ 60,170	$ 60,239	$ 86,845
Earnings per share:			
As reported -			
Basic			
Continuing operations	$ 1.86	$ 2.18	$ 3.29
Discontinued operations	0.31	0.07	0.16
Change in accounting principles	(0.17)	0.03	--
Total	$ 2.00	$ 2.28	$ 3.45
Diluted			
Continuing operations	$ 1.84	$ 2.16	$ 3.27
Discontinued operations	0.30	0.07	0.15
Change in accounting principles	(0.17)	0.03	--
Total	$ 1.97	$ 2.26	$ 3.42
Pro forma -			
Basic			
Continuing operations	$ 1.83	$ 2.15	$ 3.26
Discontinued operations	0.31	0.07	0.16
Change in accounting principles	(0.17)	0.03	--
Total	$ 1.97	$ 2.25	$ 3.42
Diluted			
Continuing operations	$ 1.82	$ 2.13	$ 3.24
Discontinued operations	0.30	0.07	0.15
Change in accounting principles	(0.17)	0.03	--
Total	$ 1.95	$ 2.23	$ 3.39

Reclassifications

"Operating revenues" and "Fuel and purchased power costs" on the accompanying 2002 and 2001 Consolidated Income Statements, have been reclassified to present realized and unrealized gains and losses under contracts in our energy marketing segment in accordance with the provisions of EITF 02-3. These provisions of EITF 02-3 were adopted on January 1, 2003 (see "Recently Adopted Accounting Pronouncements" below). The changes in presentation of these items has no impact on the Company's operating income, net income or stockholders' equity, as previously reported.

In 2003, the Company reclassified removal costs that are recoverable under our electric utility rates. These amounts, previously recorded as a component of accumulated depreciation, have been reclassified into regulatory liabilities. Amounts on the 2002 Consolidated Balance Sheet have been reclassified to conform to this presentation. The changes in presentation had no impact on the Company's stockholders' equity or results of operations, as previously reported.

In addition, certain other 2002 and 2001 amounts in the consolidated financial statements have been reclassified to conform to the 2003 presentation. These reclassifications had no effect on the Company's stockholders' equity or results of operations, as previously reported.

Recently Adopted Accounting Pronouncements

SFAS 132-R

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employer's Disclosure about Pensions and Other Postretirement Benefits" (SFAS 132-R). SFAS 132-R retains disclosure requirements of the original SFAS 132 and requires additional disclosures related to assets, obligations, cash flows, and net periodic benefit cost. SFAS 132-R is effective for fiscal years ending after December 15, 2003, except that certain disclosures are effective for fiscal years ending after June 15, 2004. Interim period disclosures are effective for interim periods beginning after December 15, 2003. The adoption of the disclosure provisions of SFAS 132-R did not have an effect on the Company's Consolidated Financial Statements (see Note 15).

SFAS 143

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 provides accounting and disclosure requirements for retirement obligations associated with long-lived assets and was effective January 1, 2003. SFAS 143 requires that the present value of retirement costs for which the Company has a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability. Cumulative accretion and accumulated depreciation will be recognized for the time period from the date the liability would have been recognized had the provisions of SFAS 143 been in effect, to the date of its adoption. The cumulative effect of initially applying SFAS 143 was recognized as a change in accounting principle.

The Company has completed a detailed review of the specific applicability and implications of SFAS 143. The review identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells in our Oil and Gas segment and reclamation of our coal mining sites in our Mining segment.

Upon adoption, the Company recorded a $2.9 million transition adjustment to properly reflect its asset retirement obligations in accordance with the provisions of SFAS 143. The transition adjustment represents the current estimated fair value of the Company's obligation to plug its oil and gas wells at the time of abandonment and an adjustment to its liability for reclaiming its coal mining sites following completion of mining activity. These activities were previously accounted for under the provisions of SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" and other industry practices and reported on the Company's consolidated balance sheet. The cumulative effect on earnings of adopting SFAS 143 was a benefit of approximately $0.2 million representing the cumulative amounts of depreciation and changes in the asset retirement obligation due to the passage of time for historical accounting periods.

The following table presents the details of the Company’s asset retirement obligations which are included on the accompanying Consolidated Balance Sheets in “Other” under “Deferred credits and other liabilities” (in thousands):

	Balance at 12/31/02	SFAS 143 Transition Adjustment	Liabilities Incurred	Liabilities Settled	Accretion	Cash Flow Revisions	Balance at 12/31/03
Oil and Gas	$ --	$ 6,133	$661(b)	$ (44)	$ 483	$ --	$ 7,233
Mining	18,513(a)	(3,214)	336	(436)	553	--	15,752
Total	$ 18,513	$ 2,919	$997	$ (480)	$ 1,036	$ --	$ 22,985

(a) December 31, 2002 balance for coal mine reclamation liability as previously accounted for under a cost-accumulation approach.

(b) The Company incurred certain asset retirement obligations with its acquisition of Mallon Resources completed on March 10, 2003, as described in Note 19.

Pro forma net income, earnings per share and liabilities have not been presented for prior periods because the pro forma application of SFAS 143 to prior periods would result in pro forma net income, earnings per share and liabilities not materially different from the actual amounts reported for those periods in the accompanying Consolidated Statements of Income and Balance Sheets.

SFAS 150

In May 2003, the FASB issued SFAS No. 150 “Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity” (SFAS 150). SFAS 150 provides accounting and disclosure requirements for classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise effective at the beginning of the first interim period beginning after June 15, 2003 (July 1, 2003 for the Company). Adoption did not have a material effect on the Company’s consolidated financial position, results of operations or cash flows.

EITF 02-3

During 2002, the EITF issued EITF 02-3. EITF 98-10, “Accounting for Contracts Involving Energy Trading and Risk Management Activities” (EITF 98-10), required that energy trading contracts be accounted for at fair value. EITF 02-3 rescinded Issue No. 98-10 effective for any new contracts entered into after October 25, 2002. For energy trading contracts entered into on or before October 25, 2002, such contracts continued to be accounted for at fair value through December 31, 2002. Effective January 1, 2003, contracts that do not meet the accounting definition of a derivative, as defined by SFAS 133, are required to be accounted for at historical cost. The Company’s energy contracts that qualify as derivatives continue to be accounted for at fair value under SFAS 133, unless those contracts meet the “normal purchase/normal sale” exclusion provided by SFAS 133 and are therefore exempted out of fair value accounting.

Upon adoption on January 1, 2003, the Company recorded a charge for a cumulative effect of an accounting change totaling approximately $2.9 million, net of tax. This cumulative effect of an accounting change was the result of certain energy contracts in our Energy Marketing segment, previously marked to fair value under EITF 98-10, being restated to reflect historical cost. The amount of the cumulative effect represents the unrealized gain or loss recorded on these contracts as of January 1, 2003. Gains and losses on these contracts are now recognized on the accrual basis of accounting. See Note 2 for further discussion of our accounting for contracts at our Energy Marketing segment subsequent to adoption of EITF 02-3.

EITF 02-3 also requires that gains and losses (realized and unrealized) on all derivative instruments within the scope of SFAS 133 be presented on a net basis in the statement of income, whether or not settled physically, if the derivative instruments are held for "trading purposes." EITF 02-3 references a definition of "trading purposes" as "active and frequent buying and selling…with the objective of generating profits on short-term differences in price." Contracts at our crude oil marketing operations are not held for "trading purposes" as defined by EITF 02-3 and meet the requirements of EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" (EITF 99-19) for a gross basis presentation on the statement of income. Upon adoption, the Company began reporting settlement amounts on contracts at our crude oil marketing operations, on a gross basis in the statement of income. Contracts at our natural gas marketing operations are held for "trading purposes", as defined by EITF 02-3, and are presented on a net basis in the statement of income. The accompanying 2002 and 2001 Consolidated Statements of Income have been reclassified to conform to this presentation.

<u>EITF 03-11</u>

On July 31, 2003, the EITF issued EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and not "held for trading purposes" as defined in Issue No. 02-3" (EITF 03-11). EITF 03-11 provides new guidance on determining whether realized gains or losses on certain derivative instruments that are not "held for trading purposes" as defined in EITF 02-3, should be shown in the income statement on a net or gross basis. The Company adopted EITF 02-3 on January 1, 2003, as discussed above. The Company adopted EITF 03-11 during the fourth quarter of 2003 with no impact on the revenue presentation adopted under the provisions of EITF 02-3.

<u>Issue C20</u>

On June 25, 2003, the FASB Derivatives Implementation Group cleared Issue C20, "Scope Exceptions: Interpretation of the Meaning of *Not Clearly and Closely Related* in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature" (Issue C20). Issue C20 clarifies which contracts qualify for the "normal purchase or sale" exception as provided by paragraph 10(b) of SFAS 133. The Company adopted this guidance on October 1, 2003. Under Issue C20, certain of the Company's long-term power sales contracts are considered derivatives as defined by SFAS 133 and do not qualify for the "normal purchase or sale" exception and therefore are required to be carried at fair value. On October 1, 2003, the terms of these contracts approximated market and therefore adoption of this guidance had no impact on the Company's results of operations and financial position. In addition, no mark-to-market adjustment was required at December 31, 2003 because the terms of the contracts continued to approximate market.

<u>FIN 46-R</u>

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). In December 2003, the FASB issued FIN No. 46 (Revised) (FIN 46-R) to address certain FIN 46 implementation issues. The Company's subsidiary, Black Hills Wyoming has an agreement with Wygen Funding, Limited Partnership, an unrelated variable interest entity (VIE) to lease the Wygen plant. Under the new accounting interpretation, as amended, the Company consolidated the VIE effective December 31, 2003. The effect of consolidating the VIE into the Company's Consolidated Balance Sheet was an increase in total assets of $129.0 million, of which $121.5 million, net of accumulated depreciation of $3.0 million, is included in Property, plant and equipment and an increase in long-term debt in the amount of $128.3 million. Prior to the December 31, 2003 consolidation, the Company recorded lease expense on the Wygen plant. Lease payments began upon completion of the plant in February 2003. During 2003, lease payments were $2.7 million and are included in Operations and maintenance on the accompanying 2003 Consolidated Statement of Income. The net effect of consolidating the income statement of the VIE on December 31, 2003, was to recognize a cumulative effect charge for $2.5 million (net of $1.4 million of income taxes), which represents the depreciation and interest expense which would have been recorded had the VIE been consolidated at inception. The net effect on future results will be to recognize depreciation and interest expense in place of recognizing lease expense, which is estimated to have an approximate $3.0 million negative annual effect to after-tax net income.

FSP 106-1

In January 2004, the FASB issued FASB Staff Position (FSP) No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-1), which permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 until remaining questions – notably the issue of how to account for the federal subsidy – are resolved. The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act. Specific guidance on the accounting for the federal subsidy provided by the 2003 Medicare Act is pending and that guidance, when issued, could require the Company to change previously reported postretirement benefit information. For more information on the Company's postretirement benefits, see Note 15.

Recently Issued Accounting Pronouncements

During the second quarter of 2003, discussion between the Securities and Exchange Commission (SEC) and FASB staffs have raised concerns over the interaction of SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" (SFAS 19) and SFAS 142. The discussion focuses on whether or not pronouncements set forth by SFAS 142 requiring more clarity in distinguishing between tangible and intangible assets, required oil and gas producing companies to reclassify amounts related to mineral rights from tangible assets to intangible assets upon adoption of SFAS 142. When the Company adopted SFAS 142 on January 1, 2002, the amounts related to mineral rights were not reclassified to intangible assets and continue to be classified in "Property, plant and equipment" on the accompanying Consolidated Balance Sheets. The SEC staff has confirmed that further discussion is needed with the FASB staff and final guidance has not yet been provided. The Company is currently monitoring the related discussion between the SEC and FASB staff and is evaluating the impact the reclassification would have on the Company's balance sheet. Any impact would be to the balance sheet and related disclosures only and will not have an effect on the Company's cash flows or results of operations.

(2) RISK MANAGEMENT ACTIVITIES

The Company's activities in the regulated and unregulated energy sector expose it to a number of risks in the normal operations of its businesses. Depending on the activity, the Company is exposed to varying degrees of market risk and counterparty risk. The Company has developed policies, processes, systems, and controls to manage and mitigate these risks.

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

- commodity price risk associated with its marketing businesses, its natural length in crude oil and natural gas production, and fuel procurement for its gas fired generation assets; and

- interest rate risk associated with variable rate credit facilities and project financing floating rate debt as described in Notes 10 and 11.

The Company's 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 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, the Company has adopted the *Black Hills Corporation Risk Policies and Procedures (BHCRPP)*. These policies have been approved by the Company's Board of Directors and are routinely reviewed by its Audit Committee. These policies include governance, control infrastructure, authorized commodities and trading instruments, prohibited activities, employee conduct, etc. The Company has an Executive Risk Committee composed of senior level executives that meets on a regular basis to review the Company's business and credit activities and to ensure that these activities are conducted within the authorized policies.

Trading Activities

Natural Gas Marketing

The Company’s natural gas marketing business specializes in producer services, end-use origination and wholesale marketing and conducts business in Western and Mid-continent regions of the United States and Canada. For producer services the 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. Origination efforts focus on supplying and providing asset optimization services to large end-use consumers of natural gas. Wholesale marketing activity has two functions: support the efforts of producer services and end-use origination groups, and market third party natural gas. These functions are predominately value-added services and rely on our ability to execute storage and transportation arbitrage opportunities.

To effectively manage the producer services, end-use origination and wholesale marketing portfolios, we enter into forward physical commodity contracts, financial instruments including over-the-counter swaps and options and transportation agreements.

Gas marketing business activities are conducted within the parameters as defined and allowed in the BHCRPP and further delineated in the gas marketing Commodity Risk Policies and Procedures (CRPP) as approved by the Executive Risk Committee. As a general policy, only limited market risk positions are permitted, as clearly defined in these policies and procedures. Therefore, substantially all of the Company’s gas marketing positions are fully hedged. The Company attempts to balance its portfolio in terms of volume and timing of performance and delivery obligations.

The Company’s natural gas marketing operations fall under the purview of EITF 02-3, SFAS 133, and for contracts entered into before October 25, 2002, in accordance with EITF 98-10. As such, all natural gas contracts entered into on or before October 25, 2002 and contracts entered after that date that meet the definition of a derivative as defined by SFAS 133, are accounted for under mark-to-market accounting. The fair values are recorded as either Derivative assets and/or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses are recorded as Operating revenues in the accompanying Consolidated Statements of Income.

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

	2003		2002	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of MMBtu's)				
Natural gas basis swaps purchased	13,028	1	28,763	1
Natural gas basis swaps sold	12,691	1	38,889	1
Natural gas fixed-for-float swaps purchased	19,645	1.5	10,675	1
Natural gas fixed-for-float swaps sold	21,752	1.5	17,934	1.25
Natural gas physical purchases	50,757	2.25	42,813	1
Natural gas physical sales	44,066	2.25	41,654	1

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2003 and 2002, and the gains and/or losses recognized in earnings. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income as of December 31, 2003 and 2002 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain (loss)
December 31, 2003	$ 26,376	$ 1,002	$ 26,495	$ 1,291	$ (408)
December 31, 2002	$ 29,559	$ 2,406	$ 28,535	$ 409	$ 3,021

Activities Other than Trading

Crude Oil Marketing

The Company has a crude oil marketing and transportation services company operating predominately in Texas, Oklahoma, and Louisiana. The Company specializes in providing independent producers with marketing and transportation services necessary to market their crude oil production to end-use markets. The main objective is to provide value in the supply chain by acting as the producer's "marketing arm" for wellhead purchasing, scheduling services, imbalance management and transportation management.

To provide these services, the Company executes forward physical crude oil purchase contracts with producers and resells into various crude oil markets. Through these transactions, the Company effectively locks in a marketing fee equal to the difference between the sales price and the purchase price, less transportation costs. The crude oil marketing portfolio is essentially hedged whereby market risk, basis risk and quality differentials are mitigated or eliminated. The Company does not speculate with the crude oil marketing portfolio with the intent to generate profits from short-term market differences. Any accepted risk will be from small differences in contract terms, index risk, or credit risk. Any risk that the Company identifies will be managed and mitigated within the guidelines stipulated in the BHCRPP.

The Company's crude oil marketing operations had historically fallen under the purview of EITF 98-10 and as such, all crude oil contracts entered into on or before October 25, 2002, had been accounted for under mark-to-market accounting. The fair values are recorded as either Derivative assets and/or Derivative liabilities on the accompanying Consolidated Balance Sheets. The net gains or losses have been recorded as Operating revenues in the accompanying Consolidated Statements of Income. With the adoption of EITF 02-3, the contracts entered into at the Company's crude oil marketing operations either do not meet the definition of derivatives under SFAS 133 or have been exempted from mark-to-market accounting as normal purchase or normal sales contracts as allowed by SFAS 133. Accordingly, none of these contracts entered into after October 25, 2002 are marked-to-market.

The contract or notional amounts and terms of our crude oil contracts at December 31, are set forth below:

	2003		2002	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of barrels)				
Crude oil purchased	2,688	0.5	4,081	0.5
Crude oil sold	2,253	0.5	4,150	0.5

As of December 31, 2003, all of the Company's crude oil marketing contracts are accounted for under the accrual method of accounting. Oil contracts entered into on or before October 25, 2002 and still in effect at December 31, 2002, were marked to fair value and the gains and/or losses recognized in earnings on December 31, 2002. The amounts related to the accompanying Consolidated Balance Sheets and Consolidated Statements of Income are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain
December 31, 2002	$ 6,776	$ --	$ 6,010	$ --	$ 766

Oil and Gas Exploration and Production

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

Hedging strategies are conducted within an enterprise wide perspective. As more fully defined below, we have some fuel procurement risk within the Company's gas-fired generation asset business. Therefore, hedging in the oil and gas segment considers any natural hedge offsets in the power generation segment. In certain cases, the Company does not hedge forecasted natural gas production when it has offsetting market risk in its fuel requirements in the power generation segment. In other words, the Company's exploration and production activities' natural length is used to offset the short position in the Company's generation activities.

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

At December 31, 2003, the Company had a portfolio of swaps to hedge portions of its crude oil and natural gas production. These transactions were previously identified as cash flow hedges, properly documented and initially met prospective effectiveness testing. At year-end, these transactions met retrospective effectiveness testing criteria and retained their cash flow hedge status.

At December 31, 2003, the derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives was reported in other comprehensive income and the ineffective portion was reported in earnings.

On December 31, 2003 and 2002 we had the following swaps and related balances (in thousands):

	Notional	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Earnings (Loss)
December 31, 2003								
Crude oil swaps	360,000	1	$ --	$ --	$1,445	$ --	$ (1,384)	$(61)
Natural gas swaps	4,830,000	1.25	172	--	1,611	25	(1,462)	(2)
			$172	$ --	$3,056	$25	$ (2,846)	$(63)
December 31, 2002								
Crude oil swaps	360,000	1	$ --	$ --	$ 976	$ --	$ (914)	$(62)
Natural gas swaps	1,650,000	1	58	--	744	--	(686)	--
			$ 58	$ --	$1,720	$ --	$ (1,600)	$(62)

*Crude in bbls, gas in MMBtu's

Most of the Company's crude oil and natural gas hedges are highly effective, resulting in very little earnings impact prior to realization. The Company estimates a portion of the unrealized earnings gains or losses currently recorded in accumulated other comprehensive income will be realized in earnings during 2004. Based on December 31, 2003 market prices, a $2.9 million loss will be realized and reported in earnings during 2004. These estimated realized losses for 2004 were calculated using December 31, 2003 market prices. Estimated and actual realized losses will likely change during 2004 as market prices change.

Power Generation

The Company has a portfolio of natural gas fueled generation assets located throughout several western states. Most of these generation assets are locked into long-term tolling contracts with third parties whereby any commodity price risk is transferred to the third party. However, we do have some natural gas fueled generation assets under long-term contracts and a few merchant plants that do possess market risk for fuel purchases.

It is the Company's policy that fuel risk, to the extent possible, be hedged. Since the Company is "long" natural gas in its exploration and production company, the Company looks at its enterprise wide natural gas market risk when hedging at the subsidiary level. Therefore, the Company attempts to hedge only enterprise wide "long" or "short" positions.

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These short positions can arise from unplanned plant outages or from unanticipated load demands. To control such risk, the Company restricts wholesale off-system sales to amounts by which the Company's anticipated generating capabilities exceed its anticipated load requirements plus a required reserve margin.

In 2001, the Company acquired several natural gas swaps when it completed the Las Vegas Cogeneration acquisition on August 31, 2001 (Note 19). The project's 53 megawatt Las Vegas I plant has a long-term fixed price power sales agreement and an index-priced natural gas purchase contract for 5,000 MMBtus per day through April 30, 2010. These swaps fixed the long-term purchase price of the index-priced natural gas purchase contract. At acquisition close, the fair value of these swaps was $6.0 million. These swaps were executed with Enron North America Corp. (Enron), which is currently in bankruptcy proceedings.

These swaps met the definition of derivatives under SFAS 133. The Company elected to treat these derivatives as cash flow hedges so that any gains or losses on the fair values of the swaps could be deferred and subsequently recognized when the underlying hedged natural gas was consumed in the plant. The swaps were properly documented and met the criteria for cash flow hedges.

During the fourth quarter of 2001, the Company determined that it was probable that Enron would default on its obligations to the Company in conjunction with these swaps. Upon that determination, the Company ceased to account for these swaps as cash flow hedges. In addition, the Company recognized a $6.0 million pre-tax valuation reserve in recognition of Enron's probable performance default and resulting consequence that the Company would not receive payment for these amounts.

Financing Activities

The Company engages in activities to manage risks associated with changes in interest rates. The Company has entered into floating-to-fixed interest rate swap agreements to reduce its exposure to interest rate fluctuations associated with its floating rate debt obligations. At December 31, 2003, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2003, the Company had $138.0 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of 2.75 years and a fair value of $(5.1) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2003 and 2002 the Company's interest rate swaps and related balances were as follows (in thousands):

	Notional	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)
December 31, 2003								
Swaps on project financing	$113,000	4.48%	2.75	$256	$ --	$3,247	$1,931	$ (4,922)
Swaps on corporate debt	25,000	5.28%	0.25	--	--	169	--	(169)
	$138,000			$256	$ --	$3,416	$1,931	$ (5,091)
December 31, 2002								
Swaps on project financing(a)	$147,000	4.98%	4	$ --	$ --	$5,104	$2,314	$ (7,418)
Swaps on corporate debt	25,000	5.28%	1	--	--	947	166	(1,113)
	$172,000			$ --	$ --	$6,051	$2,480	$ (8,531)

(a) Amounts exclude interest rate swaps related to our discontinued hydroelectric operations, sold in September 2003. At December 31, 2002, these swaps had a notional amount of $65.3 million and a fair value of $(9.8) million. The related balances are currently classified in "discontinued operations".

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2004. Based on December 31, 2003 market interest rates, $3.2 million will be realized as additional interest expense during 2004. Estimated and realized amounts will likely change during 2004 as market interest rates change.

At December 31, 2003, the Company had $424.3 million of outstanding, floating-rate debt of which $286.3 million was not offset with interest rate swap transactions that effectively convert the debt to a fixed rate. A 100 basis point increase in interest rates would cause annual interest expense to increase $2.9 million.

During the first and second quarters of 2003, the Company entered into treasury locks, with a notional amount of $150 million, to hedge the risk of interest rate movement between the hedge date and the expected pricing date for a portion of the Company's second quarter $250 million debt offering of senior unsecured notes. These swaps terminated and cash-settled during the second quarter 2003, resulting in a $4.0 million loss. These swaps were designated as cash flow hedges, and accordingly, the resulting loss will remain in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet and be amortized into earnings as additional interest expense over the life of the related long-term financing.

During 2002, the Company entered into a $50 million treasury lock to hedge a portion of the Company's $75 million First Mortgage Bond offering completed in August 2002. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. This treasury lock was treated as a cash flow hedge and accordingly the resulting loss is carried in Accumulated other comprehensive loss on the Consolidated Balance Sheet and amortized over the life of the related bonds as additional interest expense.

In addition, at December 31, 2001, the Company had a $100 million forward starting floating-to-fixed interest rate swap to hedge the anticipated floating rate debt financing related to the Company's Las Vegas II power plant. This swap terminated during the second quarter 2002 and resulted in a $1.1 million gain. This swap was treated as a cash flow hedge and accordingly in the second quarter of 2002 the resulting gain was carried in Accumulated other comprehensive income on the Consolidated Balance Sheet and was to be amortized over the life of the anticipated long-term financing. In the third quarter of 2002, this cash flow hedge was determined to be ineffective due to uncertainties about the eventual timing and form of financing for this project. As a result, $1.1 million was taken into earnings. The gain was offset by the expensing of approximately $1.0 million of deferred financing costs related to the anticipated financing.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. The Company adopted the Black Hills Corporation Credit Policy (BHCCP) that establishes guidelines, controls, and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, the Company has an Executive Credit Committee composed of senior executives that meets on a regular basis to review the Company's credit activities and to ensure that these activities are conducted within the policies adopted by the Company.

For energy marketing, production, and generation activities, the Company mitigates its credit exposure by attempting to conduct its business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements, and securing credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and asset security agreements.

The Company performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. The Company maintains a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

At the end of the year, the Company's credit exposure (exclusive of regulated utility retail customers and communications) was concentrated with investment grade companies. Approximately 63 percent of the credit exposure was with investment grade companies. For the 37 percent credit exposure with non-investment grade rated counterparties, approximately 55 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

(3) CONTRACT TERMINATION REVENUE

During the third quarter of 2003, the Company completed a transaction terminating a fifteen year contract with Allegheny Energy Supply Company, LLC, a subsidiary of Allegheny Energy, Inc., for capacity and energy at the Company's Las Vegas II power plant. The Company received a cash payment of $114.0 million, which is recorded as "Contract termination revenue" in the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment.

(4) IMPAIRMENT OF LONG-LIVED ASSETS

As a result of the contract termination discussed in Note 3, the Company assessed the recoverability of the carrying value of the Las Vegas II facility. The carrying value of the assets tested for impairment was $237.2 million. This assessment resulted in an impairment charge of $117.2 million to write down the related Property, plant and equipment by $83.1 million, net of accumulated depreciation of $5.1 million, and intangible assets by $34.1 million, net of accumulated amortization of $1.1 million. This charge reflects the amount by which the carrying value of the facility exceeded its estimated fair value determined by its estimated future discounted cash flows. This charge is included as a component of "Operating expenses" on the accompanying Consolidated Statements of Income. Operating results from the Las Vegas II power plant are included in the Power Generation segment.

(5) GUARANTEES

The Company has entered into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees of debt obligations, performance obligations under contracts and indemnification for reclamation and surety bonds.

As prescribed in FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45), the Company is required to record a liability for the fair value of the obligation it has undertaken for guarantees issued after December 31, 2002. The liability recognition requirements of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002, while the disclosure requirements are applied to all guarantees.

As of December 31, 2003 we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2003	Year Expiring
Guarantee payments under the Power Purchase and Sales Agreement with Sempra Energy Solutions	$ 10,000	Upon 5 days written notice
Guarantee payments under certain energy marketing derivative, power and gas agreements	2,500	2004
Guarantee of certain obligations under Enserco's credit facility	3,000	2004
Guarantee performance of Black Hills Wyoming under a power sales agreement	5,000	2004
Guarantee of obligation of Las Vegas Cogeneration II under an interconnection and operation agreement	750	2005
Guarantee obligations under the Wygen Plant Lease	111,100	2008
Guarantee payment and performance under credit agreements for two combustion turbines	30,214	2010
Indemnification for subsidiary reclamation/surety bonds	29,488	Ongoing
	$192,052	

The Company has guaranteed up to $10.0 million of payments of its power generation subsidiary, Las Vegas Cogeneration Limited Partnership, to Sempra Energy Solutions which may arise from transactions entered into by the two parties under a Master Power Purchase and Sale Agreement. To the extent liabilities exist under this power and purchase sale agreement subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee may be terminated for future transactions upon five days written notice.

The Company has guaranteed up to $2.5 million of commodity related payments for its energy marketing subsidiary, Enserco Energy Inc. This guarantee was provided to the counterparty in order to facilitate physical and financial transactions in energy commodities and related services. To the extent liabilities exist under the commodity- related contract subject to this guarantee, such liabilities are included in the Consolidated Balance Sheets. The guarantee expires on June 30, 2004.

The Company has guaranteed up to $3.0 million of Enserco Energy Inc.'s obligations to Fortis Capital Corp. under its credit facility. There are no liabilities on the Company's Consolidated Balance Sheets associated with this guarantee.

The Company has guaranteed up to $5 million for the performance of its wholly-owned subsidiary, Black Hills Wyoming, under a power sales agreement on the Wygen plant. The guarantee expires in February 2004, the first anniversary of commercial operation of the facility. There are no liabilities on the Company's Consolidated Balance Sheets associated with this guarantee.

The Company has guaranteed up to $0.8 million of the obligations of Las Vegas Cogeneration II, LLC under an interconnection and operations agreement for the Las Vegas II plant. To the extent liabilities exist under the interconnection and operations agreement, such liabilities are included in the Consolidated Balance Sheets. The obligation is due May 20, 2005.

The Company has also guaranteed the obligations of Black Hills Wyoming under the Agreement for Lease and Lease for the Wygen plant. The Company consolidates the Variable Interest Entity that owns the plant into its financial statements, therefore the obligations associated with this guarantee are included in the Consolidated Balance Sheets. If the lease was terminated and sold, the Company's obligation is the amount of deficiency in the proceeds from the sale to repay the investors up to a maximum of 83.5 percent of the cost of the project. At December 31, 2003, the Company's maximum obligation under the guarantee is $111.1 million (83.5 percent of $133.1 million, the cost incurred for the Wygen plant). The initial term of the lease expires in 2008 with two five-year renewal options.

The Company has guaranteed the payment of $25.9 million of debt of Black Hills Wyoming and $4.3 million of debt for another of its wholly-owned subsidiaries, Black Hills Generation. The debt is recorded on the Company's Consolidated Balance Sheets and is due December 18, 2010.

In addition, at December 31, 2003, the Company had guarantees in place totaling approximately $29.5 million for reclamation and surety bonds for its subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in the Company's Consolidated Balance Sheets.

(6) INVESTMENTS IN ASSOCIATED COMPANIES

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

- A 12.6 percent, 6.9 percent and 5.3 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., and Project Finance Fund III, L.P., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. The Company has a carrying amount in the investment of $13.8 million and $10.4 million at December 31, 2003 and 2002, respectively, which includes $1.9 million that represents the cost of the investment over the underlying net assets of the funds. As of, and for the year ended December 31, 2003, the funds had assets of $163.8 million, liabilities of $0.4 million and net income of $5.0 million. As of, and for the year ended December 31, 2002, the funds had assets of $179.2 million, liabilities of $0.8 million and net income of $18.2 million.

  Included in "Equity in earnings of unconsolidated subsidiaries" on the 2003 Consolidated Statement of Income is approximately $3.1 million related to the application of the provisions of the AICPA Audit and Accounting Guide, "Audits of Investment Companies," by the funds in which the Company invests. This guidance among other things requires investments held by investment companies to be stated at fair value. Consistent with prior periods, the Company will continue to record its portion of the net income of entities over which it exercises significant influence but which it does not control.

- A 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. The Company's carrying amount in the investment is $3.7 million and $3.4 million as of December 31, 2003 and 2002, respectively, which includes $0.6 million that represents the cost of the investment over the value of the underlying net assets of the projects. As of, and for the year ended December 31, 2003, these projects had assets of $23.9 million, liabilities of $16.0 million and net income of $0.8 million. As of, and for the year ended December 31, 2002, these projects had assets of $24.5 million, liabilities of $17.1 million and net income of $0.7 million.

(7) PROPERTY, PLANT AND EQUIPMENT

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

Regulated

	2003	2002	Lives (in years)
Electric plant:			
Production	$316,544	$313,725	25-58
Transmission	122,640	94,683	35-50
Distribution	150,748	143,629	20-40
General	29,857	31,953	7-40
Total electric plant	619,789	583,990	
Less accumulated depreciation and amortization	212,041	198,602	
Electric plant net of accumulated depreciation and amortization	407,748	385,388	
Construction work in progress	3,060	19,212	
Net electric plant	$410,808	$404,600	

2003

Non-regulated

	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	$ 66,084	$ 34,556	$ 31,528	$ 6,353	$ 37,881	3-39
Oil & gas	205,137	65,756	139,381	--	139,381	3-40
Energy marketing	27,456	2,190	25,266	382	25,648	3-40
Power generation	786,930	81,095	705,835	4,754	710,589	3-40
Communications	159,534	43,930	115,604	--	115,604	3-31.5
Other	3,075	707	2,368	143	2,511	5-7
	$ 1,248,216	$ 228,234	$ 1,019,982	$ 11,632	$ 1,031,614	

2002

	Property, Plant and Equipment	Less Accumulated Depreciation	Property, Plant and Equipment Net of Accumulated Depreciation	Construction Work in Progress	Net Property, Plant and Equipment	Lives (in years)
Coal mining	$ 63,125	$ 31,630	$ 31,495	$ 4,102	$ 35,597	3-39
Oil & gas	117,780	59,589	58,191	4,169	62,360	3-40
Energy marketing	27,016	1,062	25,954	--	25,954	3-40
Power generation	531,451	57,118	474,333	199,769	674,102	3-40
Communications	151,105	29,418	121,687	251	121,938	3-31.5
Other	714	149	565	688	1,253	5-7
	$ 891,191	$ 178,966	$ 712,225	$ 208,979	$ 921,204	

(8) COMMON STOCK

During 2003, the Company completed a public offering of its common stock through which 4.6 million shares were sold at $27 per share. Net proceeds were approximately $118 million after commissions and expenses. The proceeds were used to pay off a $50 million credit facility and to repay $68 million under the Company's 364-day revolving credit facility, which expired on August 26, 2003. In addition, in 2003 the Company issued 481,509 shares and 45,000 warrants to purchase common stock in the acquisition of Mallon Resources Corporation (see Note 19).

Equity Compensation Plans

The Company has several employee equity compensation plans, which allow for the granting of stock, restricted stock, restricted stock units, stock options and an employee stock purchase plan (ESPP Plan). The Company accounts for such plans under APB No. 25, and has adopted the disclosure-only provisions of SFAS 123.

The Company has granted options with an option exercise price equal to the fair market value of the stock on the day of the grant. The Company has 549,031 shares available to grant at December 31, 2003. Substantially all of the options granted vest one-third a year for three years (10,110 of the outstanding options vest 50 percent a year for two years) and all expire after ten years from the grant date.

A summary of the status of the stock option plans at December 31, 2003, 2002 and 2001, and changes during the years then ended are as follows:

	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	1,042,989	$27.68	992,872	$26.55	914,917	$23.43
Granted	289,665	28.01	211,985	30.04	203,000	37.09
Forfeited	(66,153)	34.31	(34,838)	33.52	(30,834)	22.13
Exercised	(55,379)	22.00	(127,030)	21.20	(94,211)	20.41
Balance at end of year	1,211,122	$27.66	1,042,989	$27.68	992,872	$26.55
Exercisable at end of year	747,482	$26.45	566,654	$25.36	445,252	$22.76

Details of outstanding options at December 31, 2003 are as follows:

Option Exercise Prices	Shares Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Shares Exercisable	Weighted Average Exercise Price
$16.67 to $22.00	377,120	$ 21.38	6.2 years	377,120	$ 21.38
$22.01 to $27.00	218,506	$ 24.33	7.4 years	152,493	$ 23.97
$27.01 to $32.00	385,790	$ 28.82	9.7 years	71,643	$ 30.92
$32.01 to $37.00	110,706	$ 34.42	8.7 years	42,935	$ 34.37
$37.01 to $38.68	79,500	$ 37.74	9.0 years	76,966	$ 37.72
$55.36	39,500	$ 55.36	8.1 years	26,325	$ 55.36

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options are as follows:

	2003	2002	2001
Weighted average fair value of options at grant date	$ 2.74	$ 6.63	$ 10.77
Weighted average risk-free interest rate	3.09%	4.17%	5.92%
Weighted average expected price volatility	46.80%	39.09%	34.92%
Weighted average expected dividend yield	4.28%	3.86%	2.90%
Expected life in years	7	7	10

For a discussion of the effect on earnings per common share for the years ended December 31, 2003, 2002 and 2001, if the Company had applied SFAS 123, see Note 1 – Stock-based Compensation.

The Company maintains the ESPP Plan under which it sells shares to employees at 90 percent of the stock's market price on the offering date. The Company issued 24,963, 17,496 and 48,368 shares of common stock under the ESPP Plan in 2003, 2002 and 2001, respectively. At December 31, 2003, 135,349 shares are reserved and available for issuance under the ESPP Plan. The fair value per share of shares sold in 2003 was $31.77 on the offering date.

During 2003 and 2001, the Company issued a total of 12,575 common shares and 36,550 common shares, respectively, as a stock bonus award to its non-officer employees. The bonuses were grossed up to cover related employee taxes. The total pre-tax compensation charge recognized by the Company was $0.3 million, $0.4 million and $1.9 million in 2003, 2002 and 2001, which was based on the market value of the stock on the grant date.

The Company issued 45,123 restricted stock units in 2003, and 24,643, 26,047 and 12,177 restricted common shares, to certain officers in 2003, 2002 and 2001, respectively. The shares carry a restriction on the officer's ability to sell the shares, until the shares vest. The shares substantially vest one-third per year over three years, contingent on employment. Compensation cost related to the awards is recognized over the vesting period. The Company recognized pre-tax compensation cost related to the awards of $0.9 million in 2003, $0.4 million in 2002 and $0.1 million in 2001.

Nonemployee stock award

During 2001, the Company issued 100,000 common shares as a charitable contribution to the newly formed not-for-profit entity, Black Hills Corporation Foundation. The charitable contribution cost included in "Other expense" on the 2001 Consolidated Statement of Income was $3.1 million, which is based on the stock market value on the grant date.

Dividend Reinvestment and Stock Purchase Plan

The Company has a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100 percent of the recent average market price. The Company has the option of issuing new shares or purchasing the shares on the open market. The Company issued 94,346 new shares in 2003 at a weighted average price of $28.90, 66,882 new shares in 2002 at a weighted average price of $28.65 and purchased shares on the open market in 2001. At December 31, 2003, 1,129,569 shares of unissued common stock were available for future offerings under the Plan.

Dividend Restrictions

Some of the Company's credit facilities contain restrictions on the payment of cash dividends under a circumstance of default or event of default. An event of default would be deemed to have occurred if the Company did not meet the financial covenant requirements for the respective facility. The most restrictive financial covenants include the following: fixed charge coverage ratio of not less than 1.5 to 1.0; a recourse leverage ratio not to exceed 0.65 to 1.00; and a minimum consolidated net worth of $475 million plus 50 percent of our aggregate consolidated net income since April 1, 2003. As of December 31, 2003, we were in compliance with the above covenants.

(9) PREFERRED STOCK

The Company has 25,000,000 authorized shares of no-par preferred stock of which 21,500 shares have been designated as the No Par Preferred Stock, Series 2000-A. At December 31, 2003, 7,771 shares of the Series 2000-A had been issued.

The Company issued 2,594 preferred shares in 2003 and no shares in 2002 related to the Indeck Capital acquisition "earn-out" provisions (see Note 14). The preferred shares issued are non-voting, cumulative, no par shares with a dividend rate equal to 1 percent per annum per share, computed on the basis of $1,000 per share plus an amount equal to any dividend declared payable with respect to the common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. The record and payment dates are the same as the record and payment dates with respect to the payment of dividends on common stock. No dividend may be declared or paid with respect to common stock unless such a dividend is declared and paid with respect to the preferred stock. The preferred stock is senior to the common stock in liquidation events.

The Company may redeem the preferred stock in whole or in part, at any time solely at its option. The redemption price per share for the preferred stock shall be $1,000 per share plus all accrued and unpaid dividends. Each share of the preferred stock is convertible at the option of the holder into common stock at any time prior to July 7, 2005 and automatically converted into common stock on July 7, 2005. Each share of preferred stock is convertible into 28.57 common shares. If the Company delivers a notice of redemption, the conversion price shall be adjusted to equal the lesser of (i) the conversion price then in effect, and (ii) the current market price on the redemption notice date.

(10) LONG-TERM DEBT

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

	2003	2002
Senior unsecured notes at 6.5% due 2013	$ 249,696	$ --
First mortgage bonds:		
9.00% repaid 2003	--	1,113
8.06% due 2010	30,000	30,000
9.49% due 2018	4,260	4,550
9.35% due 2021	29,970	31,635
8.30% due 2024	45,000	45,000
7.23% due 2032	75,000	75,000
	184,230	187,298
Other long-term debt:		
Pollution control revenue bonds at 6.7% due 2010	12,300	12,300
Pollution control revenue bonds at 7.5% due 2024	12,200	12,200
GECC Financing at 3.16% due 2010(a)(b)	30,214	32,000
Term Credit Agreement repaid 2003	--	35,000
Other	6,253	3,823
	60,967	95,323
Project financing floating rate debt(b):		
Fountain Valley project at 2.65% due 2006	132,328	138,661
Valmont and Arapahoe at 2.67% due 2007	130,632	135,000
Wygen project at 1.57% due 2006	111,100	--
Wygen project at 1.57% due 2008	17,165	--
	391,225	273,661
Total long-term debt	886,118	556,282
Less current maturities	(17,659)	(15,324)
Net long-term debt	$ 868,459	$ 540,958

(a) Floating rate debt, 86 percent secured by Gillette combustion turbine and 14 percent secured by a spare LM6000 turbine.
(b) Interest rates are presented as of December 31, 2003.

At December 31, 2003, approximately 33 percent of the Company's $424.3 million variable rate debt balance has been hedged with interest rate swaps moving the floating rates to fixed rates with a weighted average interest rate of 4.62 percent (see Note 2).

Substantially all of the Company's utility property is subject to the lien of the indenture securing its first mortgage bonds. First mortgage bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

Project financing debt is non-recourse debt collateralized by a mortgage on each respective project's land and facilities, leases and rights, including rights to receive payments under long-term purchase power contracts.

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, 2003. Some of the subsidiaries' debt agreements provide that approximately $12.4 million of the subsidiaries' cash balance at December 31, 2003 may not be distributed to the parent company.

Scheduled maturities of long-term debt for the next five years are: $17.7 million in 2004, $18.4 million in 2005, $241.1 million in 2006, $115.5 million in 2007 and $21.2 million in 2008.

(11) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $425 million at December 31, 2003 and $395 million at December 31, 2002. At December 31, 2003, these lines consist of a $225 million revolving credit facility with a term of three years, which terminates August 20, 2006 and a $200 million revolving credit facility that expires on August 27, 2004. The Company had no borrowings and $54.3 million of letters of credit and $290.5 million of borrowings and $40.3 million of letters of credit issued on the lines at December 31, 2003 and 2002, respectively. The Company has no compensating balance requirements associated with these lines of credit.

Interest rates under the facility borrowings vary and are based, at the option of the Company at the time of the loan origination, on either (i) a prime based borrowing rate (4.00 percent at December 31, 2003) or (ii) on a London Interbank Offered Rate (LIBOR) based borrowing rate or LIBOR plus 0.75 percent to LIBOR plus 1.25 percent. The one-month LIBOR rate at December 31, 2003 was 1.12 percent. In addition to interest on outstanding borrowings, the credit facilities contain a 0.25 percent annual facility fee on the total facility amount, and an annual utilization fee of 0.25 percent of the total used facility amount.

In addition to the above lines of credit, at December 31, 2003, Enserco Energy (Enserco) has a $135.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The line of credit is secured by all of Enserco's assets. The Company has made a $3.0 million guarantee to the lender associated with the line of credit. At December 31, 2003 and 2002, there were outstanding letters of credit issued under the facility of $80.3 million and $46.7 million, respectively, with no borrowing balances on the facility.

Black Hills Energy Resources (BHER) has a $25.0 million uncommitted, discretionary credit facility at December 31, 2003. The facility is secured by cash, accounts receivable and other assets. The transactional line of credit provides credit support for the purchases of crude oil of BHER. The facility allows BHER to elect up to $40.0 million of available credit via notification to the bank at the beginning of each calendar quarter. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2003 and 2002, BHER had letters of credit outstanding of $7.9 million and $13.5 million, respectively, with no borrowing balances on the facility.

The credit facilities and notes payable contain certain restrictive covenants including, among others, the maintenance of a fixed charge coverage ratio, a recourse debt-to-capitalization ratio and a total level of equity. The Company and its subsidiaries had complied with all the covenants at December 31, 2003. In addition, certain of the Company's interest rate swap agreements with a $25.0 million notional amount at December 31, 2003 include cross-default provisions. These provisions would allow the counterparty the right to terminate the swap agreement and liquidate at a prevailing market rate, in the event of default. These facilities do not contain default provisions pertaining to credit rating status.

The Company has entered into floating-to-fixed interest rate swaps to hedge a portion of its exposure to interest rate fluctuations with the above floating rate obligations. See Note 2 for further details.

(12) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments are as follows:

	2003		2002	
	(in thousands)			
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$172,771	$172,771	$ 75,045	$ 75,045
Restricted cash	$ 1,350	$ 1,350	$ 1,070	$ 1,070
Derivative financial instruments - assets	$ 27,806	$ 27,806	$ 38,799	$ 38,799
Derivative financial instruments - liabilities	$ 36,214	$ 36,214	$ 45,205	$ 45,205
Notes payable	$ --	$ --	$340,500	$340,500
Long-term debt	$886,118	$924,879	$556,282	$580,163

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

Cash and Cash Equivalents and Restricted Cash

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

Derivative Financial Instruments

These instruments are carried at fair value. Descriptions of the various instruments the Company uses and the valuation method employed are available in Note 2.

Notes Payable

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

Long-Term Debt

The fair value of the Company's long-term debt is estimated based on quoted market rates for debt instruments having similar maturities and similar debt ratings. The Company's outstanding first mortgage bonds are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for the Company to call and refinance the bonds.

(13) JOINTLY OWNED FACILITIES

The Company's subsidiary, Black Hills Power (BHP), owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 megawatt coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. BHP receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2003, BHP's investment in the Plant included $72.2 million in electric plant and $40.4 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. BHP's share of direct expenses of the Plant was $5.8 million, $5.5 million and $5.9 million for the years ended December 31, 2003, 2002 and 2001, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 14, the Company's coal mining subsidiary, Wyodak Resources, supplies coal to the Plant under an agreement expiring in 2022. This coal supply agreement is collateralized by a mortgage on and a security interest in some of Wyodak Resources' 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. Wyodak Resources' sales to the Plant were $18.7 million, $19.0 million and $21.0 million for the years ended December 31, 2003, 2002 and 2001, respectively.

BHP also owns a 35 percent interest and Basin Electric Power Cooperative owns a 65 percent interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie placed into service in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts from East to West. BHP is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. As of December 31, 2003 BHP's investment in the transmission tie was $20.3 million.

(14) COMMITMENTS AND CONTINGENCIES

Variable Interest Entity

The Company's subsidiary, Black Hills Wyoming (formerly known as Black Hills Generation), has an Agreement for Lease and Lease with Wygen Funding, Limited Partnership (the variable interest entity) for the Wygen plant. The Company is considered the "primary beneficiary" and therefore the variable interest entity has been consolidated by the Company into the accompanying consolidated financial statements (as discussed in "Recently Adopted Accounting Pronouncements" of Note 1). The initial term of the lease is five years, with two five-year renewal options, and includes a purchase option equal to the adjusted acquisition cost. The adjusted acquisition cost is essentially equal to the cost of the plant. At the end of each lease term, the Company may renew the lease, purchase the plant, or sell the plant on behalf of the variable interest entity, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the investors, the Company will be required to make a payment to the variable interest entity of the shortfall up to 83.5 percent of the adjusted acquisition cost, approximately $111.1 million. The Company has guaranteed the obligations of Black Hills Wyoming to the variable interest entity.

Acquisition Earn-out Agreement

On July 7, 2000, the Company acquired Indeck Capital, Inc. and merged it into its subsidiary, Black Hills Energy Capital, Inc. The acquisition was a stock transaction with the Company issuing 1,536,747 shares of common stock to the shareholders of Indeck priced at $21.98 per share, along with $4.0 million in preferred stock, resulting in a purchase price of $37.8 million. Additional consideration, consisting of common and preferred stock, may be paid in the form of an earn-out over a four-year period beginning in 2000. As of December 31, 2003, $8.6 million has been paid under the earn-out. On December 31, 2003, additional consideration of $5.1 million was accrued for. Additional consideration paid out under the earn-out is recorded as an increase to goodwill. The earn-out consideration is based on the acquired company's earnings during such period and cannot exceed $35.0 million in total.

Power Purchase and Transmission Services Agreements – Pacific Power

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $10.8 million in 2003, $10.9 million in 2002 (net of a $1.3 million refund for prior years) and $13.9 million in 2001.

In addition, the Company has a firm network transmission agreement for 36 MWs of capacity with PacifiCorp that expires on December 31, 2006. Annual costs are approximately $0.9 million per year. The Company uses this agreement to serve the Sheridan, Wyoming electric service territory under our contract with Montana-Dakota Utilities Company.

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were $0.5 million in 2003 and $0.7 million in each of 2002 and 2001.

Long-Term Power Sales Agreements

The Company, through its subsidiaries, has the following significant long-term power sales contracts:

- The Company has long-term power sales contracts with Public Service Company of Colorado (PSCO) for the output of several of its plants. All of the output of the Company's Fountain Valley, Arapahoe and Valmont gas-fired facilities, totaling 450 megawatts, is included under the contracts which expire in 2012. The contracts are treated as leases under accounting principles generally accepted in the United States and establish capacity and availability payments over the lives of the contracts. The contracts are tolling arrangements in which the Company assumes no fuel price risk.

- The Company has a ten-year power sales contract with Cheyenne Light, Fuel and Power (CLF&P) for the output of the 40 megawatt gas-fired Gillette CT. The Company assumes fuel price risk under this agreement since the fuel price is fixed at the outset of each month and CLF&P has the right to dispatch the facility on a day-ahead basis. The Company is permitted to remarket the energy that is not prescheduled by CLF&P. This agreement has been temporarily assigned from CLF&P to its affiliate, PSCO, for the four-year term of CLF&P's all requirements power purchase agreement with PSCO, which expires December 31, 2007.

- The Company has a ten-year contract with CLF&P for 60 megawatts of contingent capacity from the 90 megawatt Wygen plant. The Company has consented, subject to receipt of lender approval, to CLF&P's assignment of this agreement to its affiliate, PSCO, for the term of its all requirements power purchase agreement, which expires December 31, 2007. Twenty megawatts of the remaining capacity of this plant has been sold under a ten year unit contingent contract with the Municipal Energy Agency of Nebraska (MEAN).

- The Company has a ten-year power sales contract with the MEAN for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant.

- The Company has a long-term contract for the output of the 53 megawatt Las Vegas I plant with Nevada Power through 2024.

- The Company has entered into a five-year tolling agreement with Southern California Edison for 100 megawatts of capacity and energy from the Company's gas-fired Harbor Cogeneration plant. The agreement is seasonal and runs from June through October of each year. The agreement expires in 2007.

- The Company has a contract with Montana-Dakota Utilities Company, expiring in 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are served by the Company's electric utility and are integrated into our control area and are treated as firm native load.

Transmission Services Agreement

On April 21, 2003, Las Vegas Cogeneration II, LLC renewed, for a period of five years, a Firm Point-To-Point Transmission Service Agreement (TSA) with Nevada Power Company (NPC). The TSA provided transmission service in support of a Capacity and Ancillary Services Sale and Tolling Services Agreement with Allegheny Energy Supply Company, LLC (Allegheny) by which Allegheny purchased and sold on a wholesale basis the entire output of the Las Vegas II power plant. On September 22, 2003, Las Vegas Cogeneration II, LLC terminated the Allegheny tolling agreement. On December 19, 2003, Las Vegas Cogeneration II, LLC entered into a Confirmation Agreement under the Western Systems Power Pool Agreement (the Confirmation) with NPC, under which Las Vegas Cogeneration II, LLC entered into a ten year sales agreement to sell electric capacity and energy to NPC. The Confirmation was approved by the Nevada Public Utilities Commission on March 4, 2004. The Las Vegas II plant is interconnected with NPC's transmission system through a step-up transformer owned by Las Vegas Cogeneration II, LLC, pursuant to an interconnection agreement on file with FERC. Annual costs under the TSA are approximately $3.4 million to $4.8 million based on an estimate of the tariff charge, currently under regulatory review. To the extent that transmission rights established under the TSA cannot be remarketed, costs under the agreement may not be recoverable.

Reclamation Liability

Under its mining permit, Wyodak Resources is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land with an equivalent amount added to the asset costs. The asset is depreciated over the appropriate time period and the liability is accreted over time using an interest method of allocation. Approximately $0.6 million was charged to accretion expense, of which $0.3 million was reclamation expense, and $0.3 million was charged to depreciation expense for the year ended December 31, 2003. Approximately $0.9 million and $0.8 million was charged to operations as reclamation expense in 2002 and 2001, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $15.8 million and $18.5 million at December 31, 2003 and 2002, respectively.

Legal Proceedings

Forest Fire Claims

In September 2001, a fire occurred in the Southwestern Black Hills, now known as the "Hell Canyon Fire." It is alleged that the fire occurred when a high voltage electrical span maintained by the Company's electric utility, Black Hills Power, Inc. ("BHP"), broke, and electrical arcing from the severed line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National Forest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against BHP, in the Seventh Judicial Circuit Court, Fall River County, South Dakota, on or about January 31, 2003. The Complaint seeks recovery of damages for alleged fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. A substantially similar suit was filed against BHP by the United States Forest Service, on June 30, 2003, in the United States District Court for the District of South Dakota, Western Division. The State subsequently joined its claim in the federal action. The State claims damages in the amount of approximately $0.8 million for fire suppression and rehabilitation costs. The United States Government's claim for fire suppression and related costs has been submitted at approximately $1.3 million. The Company continues to investigate the cause and origin of the fire, and the damage claims. A trial date has been set for early 2005. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the "Grizzly Gulch Fire." Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes, and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by BHP.

On September 6, 2002, the State of South Dakota commenced litigation against BHP, in the Seventh Judicial Circuit Court, Pennington County, South Dakota. The Complaint seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A claim for treble damages was asserted with respect to the claim for injury to timber.

On March 3, 2003, the United States of America filed a similar suit against BHP, in the United States District Court, District of South Dakota, Western Division. The federal government's Complaint likewise seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A similar claim for treble damages is asserted with respect to the claim for injury to timber. In April 2003, the State of South Dakota intervened in the federal action. Accordingly, the state court litigation has been stayed, and all governmental claims will be tried in U.S. District Court.

The state and federal government claim approximately $5.3 million for suppression costs, $1.2 million for rehabilitation costs, and $0.6 million for timber loss. Additional claims could be asserted for alleged loss of habitat and aesthetics or for assistance to private landowners.

BHP is completing its own investigation of the fire cause and origin. BHP's investigation is continuing, but based upon information currently available, BHP filed its Answer to the Complaints of both the State and the United States government, denying all claims, and asserting that the fire was caused by an independent intervening cause, or an act of God. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April through November 2003, various private civil actions were filed against BHP, asserting that the Grizzly Gulch Fire caused damage to the parties' real property. These actions were filed in the Fourth Judicial Circuit Court, Lawrence County, South Dakota. The Complaints seek recovery on the same theories asserted in the governmental Complaints, but most of the Complaints specify no amount for damage claims. The Company will vigorously defend these matters as well.

Additional claims could be made for individual and business losses relating to injury to personal and real property, and lost income.

Although we cannot predict the outcome or the viability of potential claims with respect to either fire, based on the information available, management believes that any such claims, if determined adversely to the Company, will not have a material adverse effect on the Company's financial condition or results of operations.

PPM Energy, Inc. Demand for Arbitration

On January 2, 2004, PPM Energy, Inc. delivered its Demand for Arbitration to BHP. The Demand alleges claims for breach of contract and requests a declaration of the parties' rights and responsibilities under an Exchange Agreement executed on or about April 3, 2001. Specifically, PPM Energy asserts that the Exchange Agreement obligates BHP to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM Energy requests an award of damages in an amount not less than $20.0 million. The Company denies all claims and will vigorously defend this matter, the timing and outcome of which is uncertain.

Commodity Futures Trading Commission Investigation

In March 2003, the Company received a request for information from the Commodity Futures Trading Commission, or CFTC, calling for the production, among other things, of “all documents relating to natural gas and electricity trading” in connection with CFTC’s industry wide investigation of trade and trade reporting practices of power and natural gas trading companies. The Company cooperated fully with the CFTC producing documents and other materials in response to specific requests relating to the reporting of natural gas trading information to energy industry publications, conducted its own internal investigation into the accuracy of information that former employees of Enserco Energy Inc., its gas marketing subsidiary, voluntarily reported to trade publications, and provided detailed reports of its own investigation to the CFTC.

On July 31, 2003, the Company announced that a settlement was reached with the CFTC related to the Enserco investigation, whereby the Company agreed to pay a civil monetary penalty of $3.0 million. This charge was recorded in the second quarter and is included in Administrative and general expenses on the accompanying Consolidated Statement of Income for 2003. The settlement order recites findings of fact relating to conduct over a time period ending in June 2002 and states that the persons responsible for the misconduct no longer work for the Company. The CFTC found that the activity violated certain provisions of the Commodity Exchange Act relating to the delivery of false market information. Neither the Company nor Enserco admitted or denied these findings. The CFTC found no evidence that the Company had knowledge of, or participated in, the misconduct. The CFTC also cited efforts of the Company both before and after the inception of the investigation, to employ industry experts to assist the Company in enhancing risk management activities and internal controls on marketing activities, and the adoption by the Company of new procedures designed to prevent a reoccurrence of alleged misconduct. The Company does not believe inaccurate trade reporting to trade publications affected the financial accounting treatment of any transactions recorded in its books and records. The Company is considering its rights relative to the individuals it believes to be responsible for the conduct in question. Although the Company agreed to this civil monetary penalty with the CFTC, we cannot guarantee that other legal proceedings, civil or criminal fines or penalties, or other regulatory action related to this issue will not occur which, in turn, could adversely affect the Company’s financial condition or results of operations.

Federal Energy Regulatory Commission (FERC) Investigation

In August 2001, the Company purchased a partnership interest in the 53 megawatt Las Vegas Cogeneration I Facility from an affiliate of Enron. The partnership is called Las Vegas Cogeneration, L.P (LV Cogen). The prior owner certified to us and to relevant governmental authorities that the facility complied with all regulations necessary to obtain and maintain “qualifying facility” status under the Public Utility Regulatory Policies Act of 1978 (PURPA). Qualifying facilities are allowed to sell their output to electric utilities at “avoided cost” rates, which are usually higher than prevailing market-based rates. The prior owner contracted with NPC to sell 45 megawatts of the facility’s output during the periods of peak electricity consumption at avoided cost rates. In connection with acquiring the facility, we assumed this contract.

On February 24, 2003, FERC issued an order announcing an investigation to determine whether Enron’s ownership of the Las Vegas I plant violated the qualifying facility regulations under PURPA. In addition, the SEC issued an initial decision concluding that Enron is an electric utility and is thus not exempt from regulations under the Public Utility Holding Company Act of 1935 (PUHCA), that, among other things, prohibit electric utilities from owning more than 50 percent of a qualifying facility. Enron is appealing this decision.

The FERC investigation did not relate to the 224 megawatt gas-fired facility owned and operated by Las Vegas Cogeneration II, LLC and located on the same site in North Las Vegas, Nevada. This facility is not now, and never was certified as a qualifying facility under PURPA.

If FERC determines that Enron violated the qualifying facility regulations with respect to the Las Vegas I plant, the Company, as a partner in the entity that now owns that facility, could be liable for any refunds, fines or other penalties FERC imposes. The Company could also be subject to additional liabilities resulting from third party claims.

On November 10, 2003, LV Cogen filed with FERC an uncontested settlement among itself, FERC Staff, and intervenors that if approved by FERC would resolve all issues in the proceeding and result in termination of the investigation. On December 11, 2003, the presiding administrative law judge certified the uncontested settlement to FERC, and on January 28, 2004, FERC issued an order approving the settlement and terminating the proceeding.

Order to Show Cause

On June 25, 2003, FERC issued an order to Enron Power Marketing, Inc. (EPMI), Enron Energy Services, Inc. (EES), and a number of other market participants to show cause why their behavior during January 1, 2000, to June 20, 2001, did not constitute gaming and/or anomalous behavior, as defined in the tariffs of the California Independent System Operator (CAISO) and California Power Exchange (CAPX) (the FERC Show Cause Order). LV Cogen is among the named respondents in the FERC Show Cause Order. The Company acquired its partnership interest in LV Cogen on August 31, 2001, a date following the close of the period of inquiry under the FERC Show Cause Order.

The FERC Show Cause Order alleged that EPMI and/or EES formed partnerships and alliances with utilities, public power districts, municipalities, and qualifying facilities and used the partnerships and alliances to gain market share, acquire commercially sensitive data, acquire decision-making authority, and promote reciprocal dealing and equity share of profits, all in an effort to “game the market.” The FERC Show Cause Order directed the named respondents to show cause, in a trial-type evidentiary proceeding to be held before a FERC administrative law judge, why they should not be found to have engaged in “gaming practices” in violation of the CAISO’s and CAPX’s tariffs. The FERC Show Cause Order indicated that FERC would seek disgorgement of unjust profits associated with any violations or other additional appropriate remedies.

Pursuant to the FERC Show Cause Order, LV Cogen submitted its response to the show-cause order on September 2, 2003, submitted testimony and exhibits as its evidentiary case-in-chief on October 3, 2003, and has complied with data requests propounded by both the Commission Trial Staff (“Staff”) and the California Parties. On December 19, 2003, LV Cogen and the California Parties entered into an agreement pursuant to which the California Parties have agreed, subject to conditions and commitments specified in the agreement, not to oppose a motion by FERC Staff to dismiss LV Cogen from further proceedings under Docket Nos. EL03-180-000, et al. On January 7, 2004, FERC Staff filed a motion with FERC requesting dismissal of LV Cogen from any further proceedings under Docket Nos. EL03-180-000, et al. (Motion to Dismiss). In its Motion to Dismiss, FERC Staff concludes that it “has found no evidence that LV Cogen engaged in any Gaming Practices with EPMI, nor any evidence that LV Cogen intended to facilitate EPMI’s engagement in any Gaming Practice or had any knowledge of EPMI’s practices in selling power.” On March 3, 2004, FERC entered its Order granting FERC Staff’s Motion to Dismiss.

Price Reporting Class Actions

A. Cornerstone Propane Partners, L.P.

On August 18, 2003, Cornerstone Propane Partners, L.P. commenced a putative class action lawsuit against over thirty energy companies. *Cornerstone Propane Partners, L.P. v. Reliant Energy Services, Inc., et. al., Civ. No. 03-CV-6168 (U.S. District Court, Southern District of New York)(“Cornerstone Propane Litigation”).* The Complaint, which names Black Hills Corporation and Enserco Energy Inc. as defendants, asserts claims for an unspecified amount of damages, based upon alleged violations of the Commodity Exchange Act. General allegations in the Complaint assert that defendants manipulated natural gas futures contracts through false reporting of prices and volumes. Similar specific allegations are made against Black Hills Corporation and Enserco, based upon claims that former traders at Enserco reported false price and volume information to trade publications. Other defendants are alleged to have manipulated spot market gas prices by engaging in “wash trades” and/or by “churning” natural gas trades. Initially, the plaintiff seeks an order certifying the proceeding as a class action according to applicable rules. The Company will deny all claims for damages and vigorously defend this action, beginning with the request for class certification. The Company cannot predict the outcome of this litigation, but based upon information currently available to the Company, we believe the likelihood that the action would have a material adverse effect upon its financial condition and results of operations is remote.

B. Roberto E. Calle Gracey

On October 1, 2003, Roberto E. Calle Gracey commenced a putative class action lawsuit against a group of defendants that sets forth claims and demands similar to those described above with respect to the *Cornerstone Propane Litigation*. Black Hills Corporation and Enserco Energy, Inc. are named as defendants in this action as well. *Gracey v. American Electric Power Company, Inc., et. al., Civ. No., 03-CV-7750 (U.S. District Court, Southern District of New York).* The Company will deny all claims for damages and vigorously defend this action, beginning with the request for class certification. The Company cannot predict the outcome of this litigation, but based upon information currently available to the Company, we believe the likelihood that the action would have a material adverse effect upon its financial condition and results of operations is remote.

C. In re Natural Gas Commodity Litigation

On December 5, 2003, the actions cited in paragraphs A and B above, were consolidated with other actions involving similar claims against other parties, in a civil action captioned *In re Natural Gas Commodity Litigation*, 03 CV 6186(VM), United States District Court, Southern District of New York. All further proceedings relative to these matters will be conducted in the consolidated action.

Settlement

In 2001, the Company reached a settlement of ongoing litigation with PacifiCorp concerning the parties' rights and obligations under the Further Restated and Amended Coal Supply Agreement dated May 5, 1987, under which PacifiCorp purchased coal from the Company's coal mine to meet the coal requirements of the Wyodak power plant. The Settlement Agreement provided for the dismissal of the litigation and the execution of several new coal-related agreements between the parties. The parties agreed to terminate the Further Restated and Amended Coal Supply Agreement, and replace it with the New Restated and Amended Coal Supply Agreement (New Agreement). Under the New Agreement, the Company received an extension of sales beyond the 2013 term of the former Coal Supply Agreement and PacifiCorp received a price reduction for each ton of coal purchased. The New Agreement further provided for a special one-time payment by PacifiCorp in the amount of $7.3 million, which was received in 2001. This payment primarily related to disputed billings under the previous agreement and a value transfer premium. Of this payment, $5.6 million was recognized in 2001 and is included in Other income on the accompanying Consolidated Statements of Income, $1.0 million was previously recognized in revenues and the remaining $0.7 million is being recognized as sales are made under the New Agreement. The Company also sold the "North Conveyor System" to PacifiCorp, which served as the backup coal delivery system for the Wyodak power plant which in 2001 resulted in a $2.6 million gain that is included in "Other income" on the accompanying Consolidated Statements of Income.

Ongoing Proceedings

The Company is subject to various other legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the consolidated financial position or results of operations of the Company.

(15) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company and those of the following subsidiaries, Black Hills Power, Wyodak Resources Development Corp., Black Hills Exploration and Production and Daksoft who meet certain eligibility requirements. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity securities and cash equivalents. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2003	2002
	(in thousands)	
Projected benefit obligation at beginning of year	$ 50,888	$ 43,016
Service cost	1,293	979
Interest cost	3,351	3,135
Actuarial loss	2,199	951
Discount rate change	6,414	4,926
Benefits paid	(2,221)	(2,368)
Amendments	--	249
Taxable wage rate and cost of living rate change	(45)	--
Net increase	10,991	7,872
Projected benefit obligation at end of year	$ 61,879	$ 50,888

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

	2003	2002
	(in thousands)	
Beginning market value of plan assets	$ 32,437	$ 41,268
Benefits paid	(2,221)	(2,368)
Investment income (loss)	8,081	(6,463)
Employer contributions	10,500	--
Ending market value of plan assets	$ 48,797	$ 32,437

Funding information for the Plan is as follows:

	2003	2002
	(in thousands)	
Fair value of plan assets	$ 48,797	$ 32,437
Projected benefit obligation	(61,879)	(50,888)
Funded status	(13,082)	(18,451)
Unrecognized:		
Net loss	24,170	21,971
Prior service cost	1,609	1,841
Net amount recognized	$ 12,697	$ 5,361

Amounts recognized in statement of financial position consist of:

	2003	2002
	(in thousands)	
Net pension (liability) asset	$ 12,697	$ (8,954)
Intangible asset	--	1,841
Accumulated other comprehensive loss	--	12,474
Net amount recognized	$ 12,697	$ 5,361
Accumulated benefit obligation	$ 48,581	$ 41,391

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $12.7 million at December 31, 2003 and is included in the line item Other Assets on the accompanying Consolidated Balance Sheets.

The provisions of SFAS No. 87 required the Company to record an accrued pension liability of $8.9 million at December 31, 2002 and is included in the line item Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets.

Components of Net Periodic Pension Expense

	2003	2002	2001
		(in thousands)	
Service cost	$ 1,293	$ 979	$ 945
Interest cost	3,351	3,135	3,080
Expected return on assets	(3,119)	(4,206)	(5,814)
Amortization of prior service cost	232	231	231
Recognized net actuarial (gain) loss	1,407	102	(556)
Net pension (income) expense	$ 3,164	$ 241	$ (2,114)

Additional Information

	2003	2002
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ 12,474	$ (12,474)

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2003	2002
Discount rate	6.00%	6.75%
Rate of increase in compensation levels	5.00%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2003	2002	2001
Discount rate*	6.75%	7.50%	7.50%
Expected long-term rate of return on assets**	10.00%	10.50%	10.50%
Rate of increase in compensation levels	5.00%	5.00%	5.00%

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* The discount rate used for net periodic pension cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic pension cost. This change is expected to affect pension costs in 2004 by an increase of approximately $0.7 million.

** The expected rate of return on plan assets was changed from 10.0 percent in 2003 to 9.5 percent for the calculation of the 2004 net periodic pension cost. This change is expected to increase pension costs in 2004 by approximately $0.2 million.

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

The expected long-term rate of return for equity investments was 10.5 percent and 11.0 percent for the 2003 and 2002 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2002, 12.5 percent, 10.5 percent, 10.3 percent and 10.9 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term treasury bonds.

Plan Assets

Percentage of fair value of Plan assets at September 30:

	2003	2002
Domestic equity	44.8%	63.0%
Foreign equity	26.6	25.9
Fixed income	3.8	7.8
Cash	24.8(a)	3.3
Total	100.0%	100.0%

(a) Allocation includes $10.5 million cash contribution made to the plan on September 30, 2003; the contribution is expected to be placed in noncash investments in the fiscal 2004 plan year.

The Plan’s investment policy includes a target asset allocation as follows:

Asset Class	Target Allocation
US Stock	60% (with a variance of no more or less than 10% of target)
Foreign Stocks	30% (with a variance of no more or less than 10% of target)
Fixed Income	5% (with a variance of no more than 10% or no less than 5% of target)
Cash	5% (with a variance of no more than 10% or no less than 5% of target)

The Plan’s investment policy includes the investment objective that the achieved long-term rate of return meet or exceed the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity-based assets. The policy provides that the Plan will maintain a passive core US Stock portfolio based on the S&P 500 Index. Complementing this core will be investments in US and foreign equities through actively managed mutual funds.

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

Contributions

The Company made a contribution to the Plan of $10.5 million on September 30, 2003. The Company does not anticipate that a contribution will be made to the Plan in the 2004 fiscal year.

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The Plans are nonqualified defined benefit plans. The Company uses a September 30 measurement date for the Plans.

Obligations and Funded Status

	2003	2002
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 11,303	$ 5,826
Service cost	425	240
Interest cost	759	432
Actuarial losses	6,107	5,095
Benefits paid	(120)	(120)
Plan amendments	--	(170)
Discount rate change	2,256	--
Taxable wage rate and cost of living rate change	107	--
Change in salary projection	(4,643)	--
Net increase	4,891	5,477
Projected benefit obligation at end of year	$ 16,194	$ 11,303
Fair value of plan assets at end of year	$ --	$ --
Funded status	(16,194)	(11,303)
Unrecognized net loss	10,577	7,261
Unrecognized prior service cost	62	60
Contributions	30	30
Net amount recognized	$ (5,525)	$ (3,952)

	2003	2002
	(in thousands)	
Amounts recognized in consolidated balance sheets consist of:		
Net pension (liability)	$ (8,886)	$ (5,124)
Intangible asset	68	60
Contributions	30	30
Accumulated other comprehensive loss	3,263	1,082
Net amount recognized	$ (5,525)	$ (3,952)
Accumulated benefit obligation	$ 8,886	$ 5,125

The provisions of SFAS 87 required the Company to record a net pension liability of $8.9 million and $5.1 million at December 31, 2003 and 2002, respectively. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets.

Components of Net Periodic Benefit Cost

	2003	2002	2001
	(in thousands)		
Service cost	$ 425	$ 240	$ 138
Interest cost	759	432	294
Prior service cost	(2)	26	25
Loss	511	145	36
Net periodic benefit cost	$ 1,693	$ 843	$ 493

Additional Information

	2003	2002
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ (2,181)	$ (1,082)

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2003	2002
Discount rate	6.00%	6.75%
Rate of increase in compensation levels	5.00%	5.00%

Weighted-average assumptions used to determine net periodic benefit cost for plan year	2003	2002	2001
Discount rate*	6.75%	7.50%	7.50%
Rate of increase in compensation levels	5.00%	5.00%	5.00%

*The discount rate used for net periodic benefit cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic benefit cost. This change is expected to affect benefit costs in 2004 by an increase of approximately $0.2 million.

Plan Assets

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

Contributions

The Company anticipates that contributions to the plans for the next fiscal year will be approximately $0.8 million; the contributions are expected to be in the form of benefit payments.

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in the Company’s Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a September 30 measurement date for the Plan.

These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plan.

Obligation and Funded Status

	2003	2002
	(in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of year	$ 8,647	$ 8,952
Service cost	383	284
Interest cost	576	519
Plan participant's contributions	381	374
Amendments	--	(360)
Benefits paid and actual expenses	(606)	(664)
Actuarial (gains) losses	1,770	(458)
Net increase	2,504	(305)
Accumulated postretirement benefit obligation at end of year	$ 11,151	$ 8,647
Fair value of plan assets at end of year	$ --	$ --
Funded status	(11,151)	(8,647)
Unrecognized net loss	3,882	2,202
Unrecognized prior service cost	(311)	(336)
Unrecognized transition obligation	1,348	1,498
Contributions	60	53
Net amount recognized	$ (6,172)	$ (5,230)

Amounts recognized on the accompanying Consolidated Balance Sheets consist of:

	2003	2002
	(in thousands)	
Accrued postretirement liability	$ (6,172)	$ (5,230)

Components of Net Periodic Benefit Cost

	2003	2002	2001
	(in thousands)		
Service cost	$ 383	$ 284	$ 289
Interest cost	576	519	507
Amortization of transition obligation	150	150	150
Amortization of prior service cost	(24)	(24)	--
Loss	89	35	21
Net periodic benefit cost	$ 1,174	$ 964	$ 967

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2003	2002
Discount rate	6.00%	6.75%

Weighted-average assumptions used to determine net periodic benefit cost for plan year	2003	2002	2001
Discount rate*	6.75%	7.50%	7.50%

*The discount rate used for net periodic benefit cost was changed from 6.75 percent in 2003 to 6.0 percent for the calculation of the 2004 net periodic benefit cost. This change is expected to affect benefit costs in 2004 by an increase of approximately $0.2 million.

The healthcare cost trend rate assumption for the 2003 fiscal year expense was 11 percent for fiscal 2003 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2009. The health care trend rate assumption for 2003 fiscal year disclosure and 2004 fiscal year expense is 12 percent for fiscal 2004 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011.

The healthcare cost trend rate assumption has a significant effect on the amounts reported. A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 22 percent and the accumulated periodic postretirement benefit obligation $1.6 million or 14 percent. A 1 percent decrease would reduce the service and interest cost by $0.2 million or 17 percent and the accumulated periodic postretirement benefit obligation $1.2 million or 11 percent.

Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

Contributions

The Company anticipates that contributions to the plan for the next fiscal year will be approximately $0.6 million in the form of benefits and administrative costs paid.

Defined Contribution Plan

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. The Company provides a matching contribution of 100 percent of the employee’s tax-deferred contribution up to a maximum 3 percent of the employee’s eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company’s matching contributions totaled $1.4 million for 2003, $1.3 million for 2002 and $0.9 million for 2001.

(16) OTHER COMPREHENSIVE INCOME (LOSS)

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

	2003		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$10,293	$(3,603)	$ 6,690
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $(331))	(592)	44	(548)
Reclassification adjustment for interest rate swaps designated as cash flow hedges settled as part of the hydroelectric asset sale and included in net income (net of minority interest share of ($2,379))	6,361	(2,433)	3,928
Other comprehensive income (loss)	$16,062	$(5,992)	$10,070

	2002		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
Minimum pension liability adjustments	$ (13,556)	$4,745	$ (8,811)
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $(164))	(13,342)	4,703	(8,639)
Other comprehensive income (loss)	$ (26,898)	$9,448	$ (17,450)

	2001		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Unrealized gain on securities during the year	$ 1,775	$ (337)	$ 1,438
Initial impact of adoption of SFAS 133 (net of minority interest share of $2,627)	(7,635)	3,125	(4,510)
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $248)	336	(193)	143
Other comprehensive income (loss)	$ (5,524)	$ 2,595	$ (2,929)

(17) INCOME TAXES

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

	2003	2002	2001
		(in thousands)	
Current:			
Federal	$ 35,691	$ (3,735)	$ 36,332
State	5,235	(1,494)	1,986
	40,926	(5,229)	38,318
Deferred:			
Federal	(6,583)	30,340	10,141
State	(4,105)	2,212	83
Tax credit amortization	(318)	(416)	(432)
	$ 29,920	$ 26,907	$ 48,110

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

Years ended December 31,	2003	2002
	(in thousands)	
Deferred tax assets, current:		
Valuation reserves	$ 2,824	$ 1,655
Mining development and oil exploration	980	1,008
Employee benefits	6,216	4,151
Items of other comprehensive income	2,375	7,560
Other	1,586	1,678
	13,981	16,052
Deferred tax liabilities, current:		
Prepaid expenses	1,733	1,020
State income taxes	2,520	6,002
Derivative fair value adjustments	850	723
Employee benefits	4,397	2,226
Items of other comprehensive income	160	--
Other	92	75
	9,752	10,046
Net deferred tax asset, current	$ 4,229	$ 6,006
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 102	$ 6,779
Mining development and oil exploration	213	196
Regulatory asset	1,616	1,866
Deferred revenue	1,148	937
Items of other comprehensive income	2,866	4,820
Net operating loss	4,927	1,102
Asset impairment	41,023	--
Other	11,717	5,190
	63,612	20,890
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	135,614	125,363
Regulatory liability	4,320	4,350
Mining development and oil exploration	20,445	11,594
Derivative fair value adjustments	614	1,317
Other	27,660	10,911
	188,653	153,535
Net deferred tax liability, non-current	$125,041	$132,645
Net deferred tax liability	$120,812	$126,639

The following table reconciles the change in the net deferred income tax liability from December 31, 2002, to December 31, 2003, to deferred income tax expense:

	2003
	(in thousands)
Net change in deferred income tax liability from the preceding table	$ (5,827)
Deferred taxes associated with 2002 Federal Income Tax Return True-up primarily related to accelerated depreciation and other plant-related differences	(20,456)
Deferred taxes associated with other comprehensive loss	(5,992)
Deferred taxes related to discontinued operations	14,912
Deferred taxes related to change in accounting principle	1,251
Deferred taxes related to net operating loss acquisitions	4,927
Other	179
Deferred income tax benefit for the period	$(11,006)

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

	2003	2002	2001
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	0.8	0.5	1.4
Amortization of excess deferred and investment tax credits	(0.5)	(0.6)	(0.3)
Percentage depletion in excess of cost	(0.9)	(0.7)	(0.8)
Research and development credit	(0.6)	(1.5)	--
Other	0.6	(1.2)	1.1
	34.4%	31.5%	36.4%

At December 31, 2003, the Company had the following net operating loss carryforwards (in thousands):

Net Operating Loss Carryforward	Expiration Year
$1,374	2017
1,464	2018
1,252	2019
14,512	2022

(18) BUSINESS SEGMENTS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2003, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six business segments that include: Wholesale Energy consisting of: Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and operates oil and natural gas interests located in the Rocky Mountain region, Texas, California and other states; Energy Marketing, which markets natural gas, oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions markets; Power Generation, which produces and sells power and capacity to wholesale customers; Electric, which supplies electric utility service to Western South Dakota, Northeastern Wyoming and Southeastern Montana; and Communications, which primarily markets communications and software development services.

December 31:	2003	2002
	(in thousands)	
Total assets		
Wholesale energy:		
Coal mining	$ 46,644	$ 42,626
Oil and gas	145,371	100,479
Energy marketing	256,059	228,543
Power generation	876,160	859,447
Electric utility	463,869	451,185
Communications	126,204	131,327
Corporate	145,025	7,899
Discontinued operations	3,893	178,468
Total assets	$ 2,063,225	$ 1,999,974
Capital expenditures and acquisitions		
Wholesale energy:		
Coal mining	$ 8,203	$ 3,635
Oil and gas	43,448	50,838
Energy marketing	822	18,734
Power generation	28,798	176,476
Electric utility	25,427	31,251
Communications	8,178	21,607
Corporate	1,815	1,377
Total capital expenditures and acquisitions	$ 116,691	$ 303,918
Property, plant and equipment		
Wholesale energy:		
Coal mining	$ 72,437	$ 67,227
Oil and gas	205,137	121,949
Energy marketing	27,838	27,016
Power generation	791,684	731,220
Electric utility	622,849	603,202
Communications	159,534	151,356
Corporate	3,218	1,402
Total property, plant and equipment	$ 1,882,697	$ 1,703,372

December 31:	2003	2002	2001
		(in thousands)	
External operating revenues			
Wholesale energy:			
Coal mining	$ 22,234	$ 20,825	$ 20,551
Oil and gas	46,648	26,043	32,869
Energy marketing(a)	675,586	553,688	390,317
Power generation(b)	284,567	102,548	50,228
Electric utility	170,942	162,186	212,355
Communications	39,763	32,677	20,258
Total external operating revenues	$ 1,239,740	$ 897,967	$ 726,578

(a) Operating revenues for energy marketing are presented in accordance with EITF 02-3 and EITF 99-19, as described in Note 1.

(b) Power generation revenue in 2003 includes $114 million of contract termination revenue as described in Note 3.

	2003	2002	2001
Intersegment operating revenues			
Wholesale energy:			
Coal mining	$ 12,545	$ 10,524	$ 11,249
Oil and gas	329	443	539
Electric utility	77	--	--
Intersegment eliminations	(2,639)	(443)	(539)
Total intersegment operating revenues(c)	$ 10,312	$ 10,524	$ 11,249

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

	2003	2002	2001
Depreciation, depletion and amortization			
Wholesale energy:			
Coal mining	$ 3,808	$ 3,358	$ 2,984
Oil and gas	10,000	7,799	7,806
Energy marketing	1,183	932	484
Power generation	31,727	21,452	10,748
Electric utility	18,999	17,499	15,773
Communications	14,515	12,678	9,944
Corporate	559	147	300
Total depreciation, depletion and amortization	$ 80,791	$ 63,865	$ 48,039
Operating income (loss)			
Wholesale energy:			
Coal mining	$ 8,617	$ 9,092	$ 6,586
Oil and gas	13,596	6,471	15,193
Energy marketing	12,151	18,065	53,662
Power generation	64,302	39,701	13,050
Electric utility	51,099	58,160	84,108
Communications	(5,241)	(7,447)	(13,250)
Corporate	(7,767)	(7,103)	(3,984)
Total operating income	$ 136,757	$ 116,939	$ 155,365

December 31:	2003	2002	2001
		(in thousands)	
Interest income			
Wholesale energy:			
Coal mining	$ 2,473	$ 3,460	$ 8,125
Oil and gas	832	2	45
Energy marketing	1,236	1,634	1,854
Power generation	23,720	22,254	8,699
Electric utility	1,512	734	4,858
Communications	--	3	15
Corporate	16,090	16,680	7,379
Intersegment eliminations	(44,787)	(44,157)	(28,895)
Total interest income	$ 1,076	$ 610	$ 2,080
Interest expense			
Wholesale energy:			
Coal mining	$ 757	$ 2,453	$ 5,752
Oil and gas	2,054	59	145
Energy marketing	885	564	17
Power generation	53,854	41,454	24,589
Electric utility	17,044	13,663	15,780
Communications	3,827	3,993	5,789
Corporate	18,945	15,535	7,298
Intersegment eliminations	(44,787)	(44,157)	(28,895)
Total interest expense	$ 52,579	$ 33,564	$ 30,475
Income taxes			
Wholesale energy:			
Coal mining	$ 2,742	$ 3,220	$ 6,266
Oil and gas	3,978	1,739	4,930
Energy marketing	5,778	6,396	20,933
Power generation	11,795	7,430	(372)
Electric utility	11,622	15,067	24,255
Communications	(3,184)	(3,948)	(6,561)
Corporate	(2,811)	(2,997)	(1,341)
Total income taxes	$ 29,920	$ 26,907	$ 48,110
Income (loss) from continuing operations before change in accounting principle			
Wholesale energy:			
Coal mining	$ 8,803	$ 8,572	$ 11,591
Oil and gas	8,400	4,783	10,197
Energy marketing	6,725	12,739	34,566
Power generation	22,429	12,523	(1,897)
Electric utility	24,089	30,217	45,238
Communications	(5,880)	(7,260)	(12,300)
Corporate	(7,569)	(2,981)	(2,560)
Intersegment eliminations	(2)	(14)	(724)
Total income from continuing operations before change in accounting principle	$ 56,995	$ 58,579	$ 84,111

(19) ACQUISITIONS

On October 1, 2002, the Company entered into a definitive merger agreement to acquire the Denver-based Mallon Resources Corporation. On March 10, 2003, the Company completed this acquisition. The total cost of the transaction was approximately $51.2 million. The total cost of the transaction includes $30.5 million for the October 2002 acquisition of Mallon's debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges, and approximately $8.4 million, which the Company loaned to Mallon prior to completion of the acquisition. Mallon shareholders received 0.044 of a share of the Company's common stock for each share of Mallon, which was equivalent to 481,509 shares of Black Hills Corporation common stock.

The acquisition was accounted for under the purchase method of accounting and, accordingly, the purchase price was allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and liabilities assumed as of the date of acquisition. The estimated purchase price allocation is subject to adjustment, generally within one year of the date of acquisition. The preliminary purchase allocation has been adjusted to reflect the completion of the quantification and analysis of the acquired asset retirement obligations in accordance with SFAS 143. This adjustment resulted in a $0.7 million increase to Long-term liabilities and Property, plant and equipment. The adjusted preliminary allocation of the purchase price is as follows (in thousands):

Current assets	$	165
Property, plant and equipment		56,283
Deferred tax asset		5,194
Total assets acquired	$	61,642
Current liabilities	$	6,343
Long-term liabilities		4,146
Total liabilities assumed	$	10,489
Net assets	$	51,153

The results of operations of the above acquired company have been included in the accompanying consolidated financial statements since the acquisition date.

The following pro forma consolidated results of operations for the years ended December 31, have been prepared as if the Mallon acquisition had occurred on January 1, 2001 (in thousands):

		2003		2002		2001
Operating revenues	$	1,252,993	$	919,552	$	757,167
Income from continuing operations	$	56,547	$	52,980	$	66,929
Net income	$	60,774	$	55,853	$	70,895
Earnings per share--						
Basic:						
Continuing operations	$	1.82	$	1.93	$	2.59
Total	$	1.95	$	2.04	$	2.72
Diluted:						
Continuing operations	$	1.80	$	1.92	$	2.55
Total	$	1.93	$	2.02	$	2.70

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

Mallon Resources' proved developed and undeveloped reserves, estimated using constant year-end product prices, as of December 31, 2002, were approximately 86 billion cubic feet of gas equivalent. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering firm selected by the Company. The reserves are located primarily on the Jicarilla Apache Nation in the San Juan Basin of New Mexico and are comprised almost entirely of natural gas in shallow sand formations. The oil and gas leases of the acquisition total more than 66,500 gross acres (56,000 net), most of which is contained in a contiguous block that is in the early stages of development.

On March 8, 2002, the Company acquired an additional 67 percent ownership interest in Millennium Pipeline Company, L.P., which owns and operates a 200-mile pipeline. The pipeline has a capacity of approximately 65,000 barrels of oil per day, and transports imported crude oil from Beaumont, Texas to Longview, Texas, which is the transfer point to connecting carriers. The Company also acquired additional ownership interest in Millennium Terminal Company, L.P., which has 1.1 million barrels of leased crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont. These acquisitions give the Company 100 percent ownership in the Millennium companies. Total cost of the acquisitions was $11.0 million and was funded through borrowings under short-term revolving credit facilities.

On March 15, 2002, the Company paid $25.7 million to acquire an additional 30 percent interest in the Harbor Cogeneration Facility (Harbor), a 98-megawatt gas-fired plant located in Wilmington, California. In addition, during the fourth quarter of 2002, the Company paid $13.8 million to acquire the remaining ownership interest in Harbor and the Pepperell Facility (Pepperell), a 40 megawatt gas-fired plant located in Pepperell, Massachusetts. These transactions gave the Company a 100 percent ownership interest in Harbor and Pepperell.

The Company's investments in the Millennium, Harbor and Pepperell entities prior to the above acquisitions were accounted for under the equity method of accounting and were included in Investments on the accompanying Consolidated Balance Sheets. Each of the above acquisitions gave the Company majority ownership and voting control of the respective entities, therefore, after acquisition the Company has consolidated each of the entities in its consolidated financial statements.

The above acquisitions have been accounted for under the purchase method of accounting and, accordingly, the purchase prices have been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of acquisition. The purchase price and related acquisition costs of Harbor exceeded the fair values assigned to net tangible assets by approximately $9.3 million, and were recorded as long-lived intangible assets.

During July 2002, the Company purchased the assets of the Kilgore to Houston Pipeline System from Equilon Pipeline Company, LLC. The Kilgore pipeline transports crude oil from the Kilgore, Texas region south to Houston, Texas, which is the transfer point to connecting carriers via the Oil Tanking Houston terminal facilities. The 10-inch pipeline is approximately 190 miles long and has a capacity of up to approximately 35,000 barrels per day. In addition, the Kilgore system has approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas. Total cost of the acquisition was $6.7 million.

The impact of these acquisitions was not material in relation to the Company's results of operations. Consequently, pro forma information is not presented.

(20) DISCONTINUED OPERATIONS

The Company accounts for its discontinued operations under the provisions of Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," (SFAS 144). Accordingly, results of operations and the related charges for discontinued operations have been classified as "Income from discontinued operations, net of tax" in the accompanying Consolidated Statements of Income. Assets and liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as "Assets of discontinued operations" and "Liabilities of discontinued operations." For comparative purposes, all prior periods presented have been restated to reflect the reclassifications on a consistent basis.

Sale of Hydroelectric Assets

On September 30, 2003 the Company sold its seven hydroelectric power plants located in Upstate New York. The aggregate cash purchase price of approximately $186 million was used in part to pay off the remaining amount of project-level debt and related interest rate swaps associated with these assets, which totaled approximately $91 million. The remaining cash proceeds from the sale are expected to be used to pay income taxes related to the sale, to repay other corporate or subsidiary-level debt, or for other corporate purposes. The purchasers are affiliates of Boralex, Inc., a Canadian corporation, and Boralex Power Income Fund, an unincorporated Canadian trust of which Boralex owns an interest (collectively the Purchaser). The agreements with the Purchaser required that the Company deliver 100 percent of the equity interests of the entities that owned the facilities and required that the Company acquire those minority interests which it did not then own, in advance of closing. In anticipation of entering into the agreements with the Purchaser, on July 8, 2003, the Company acquired the equity interests of a third party investor for $9.0 million and entered into a definitive agreement to acquire the balance of the equity interests from another third party investor. For business segment reporting purposes, the hydroelectric power plants results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations at December 31, are as follows:

	2003	2002	2001
		(in thousands)	
Operating revenues	$ 21,800	$ 27,397	$ 24,419
Pre-tax income from discontinued operations	$ 7,986	$ 8,484	$ 5,352
Pre-tax gain on disposal	13,864	--	--
Income tax expense	(11,355)	(3,152)	(1,980)
Net income from discontinued operations	$ 10,495	$ 5,332	$ 3,372

Assets and liabilities of the discontinued operations are as follows:

	December 31 2002
	(in thousands)
Current assets	$ 8,315
Property, plant and equipment	148,692
Goodwill	9,772
Other non-current assets	4,738
Current derivative liability	(4,241)
Other current liabilities	(8,747)
Long-term debt	(77,904)
Non-current derivative liability	(5,531)
Other non-current liabilities	(3,872)
Minority interest	(6,456)
Net assets of discontinued operations	$ 64,766

Adoption of Plan to Sell Pepperell Plant

During the third quarter of 2003, the Company adopted a plan to sell the 40 megawatt gas-fired Pepperell plant, which is part of the Power generation segment. The Pepperell plant is the Company's only remaining generation asset in the Eastern market and management has determined that it is a non-strategic asset. Management currently believes the assets will be sold by September 30, 2004. In connection with the plan to sell, the Company determined that the carrying value of the underlying assets exceeded their fair value and a charge to operations was required.

Consequently, in the third quarter of 2003, the Company recorded an after-tax charge of approximately $0.6 million, which represents the difference between the carrying value of the assets versus their fair value, less estimated cost to sell. For business segment reporting purposes, the Pepperell plant results were previously included in the Power Generation segment.

Revenues and net income from the discontinued operations at December 31, are as follows:

	2003	2002	2001
		(in thousands)	
Operating revenues	$ 2,152	$ 3,572	$ 5,586
Pre-tax income (loss) from discontinued operations	$ (1,422)	$ (1,115)	$ 161
Pre-tax loss on disposal	(3,464)	--	--
Income tax benefit (expense)	2,979	397	(60)
Net (loss) income from discontinued operations	$ (1,907)	$ (718)	$ 101

Assets and liabilities of the discontinued operations are as follows:

	2003	2002
	(in thousands)	
Current assets	$ 249	$ 1,798
Property, plant and equipment	1,064	4,779
Non-current deferred tax asset	2,580	374
Other current liabilities	(86)	(203)
Non-current deferred tax liability	(381)	--
Net assets of discontinued operations	$ 3,426	$ 6,748

Sale of Coal Marketing Subsidiary

During the second quarter of 2002, the Company adopted a plan to dispose of its coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. In connection with the plan of disposal, the Company determined that the carrying values of some of the underlying assets exceeded their fair values and a charge to operations was required.

Consequently, in the second quarter of 2002, the Company recorded an after-tax charge of approximately $1.0 million, which represents the difference between the carrying values of the assets and liabilities of the subsidiary versus their fair values, less cost to sell. In addition, during the first quarter of 2002, the Company had a $0.8 million (pre-tax) impairment loss of certain intangibles as a result of a weak coal market. For business segment reporting purposes, the coal marketing business results were previously included in the Energy Marketing segment.

Gross margins on energy trading contracts and net income from the discontinued operation at December 31, are as follows:

	2003	2002	2001
		(in thousands)	
Gross margins on energy trading contracts	$ --	$ 235	$ 3,660
Pre-tax income (loss) from discontinued operations	$ --	$ (2,679)	$ 886
Pre-tax loss on disposal	--	(1,588)	--
Income tax benefit (expense)	834	1,630	(393)
Net (loss) income from discontinued operations	$ 834	$ (2,637)	$ 493

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

Black Hills Exploration and Production has interests in 940 producing oil and gas properties in ten states. Black Hills Exploration and Production also holds leases on approximately 293,040 net undeveloped acres.

Costs Incurred

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

	2003	2002	2001
Acquisition of properties:			
Proved	$ 21,075	$ 162	$ 6,733
Unproved	19,994	2,331	2,967
Exploration costs	4,089	2,367	2,676
Development costs	19,377	11,699	13,221
Company's share of equity method investees' costs of property acquisition, exploration and development	1,067	--	--
	$ 65,602	$ 16,559	$ 25,597

Reserves

The following table summarizes Black Hills Exploration and Production's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2003, 2002 and 2001, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering company selected by the Company. Such reserve estimates are based upon a number of variable factors and assumptions, which may cause these estimates to differ from actual results.

	2003		2002		2001	
	Oil	Gas	Oil	Gas	Oil	Gas
	(in thousands of barrels of oil and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	4,880	28,513	4,055	24,071	4,413	18,404
Production	(405)	(8,548)	(455)	(4,707)	(446)	(4,615)
Additions	364	91,736	188	8,504	749	19,111
Property sales	--	--	(11)	--	--	--
Revisions to previous estimates	550	12,361	1,103	645	(661)	(8,829)
Balance at end of year	5,389	124,062	4,880	28,513	4,055	24,071
Proved developed reserves at end of year included above	4,830	66,294	4,188	27,473	2,962	22,420
Year-end prices (average well-head)	$30.56	$ 4.63	$29.24	$ 3.41	$18.12	$ 2.05

Capitalized Costs

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

	2003	2002	2001
Unproved oil and gas properties	$ 22,705	$ 5,109	$ 4,912
Proved oil and gas properties	162,116	111,227	94,862
	184,821	116,336	99,774
Accumulated depreciation, depletion & amortization and valuation allowances	(61,928)	(56,488)	(49,771)
Net capitalized costs	$122,893	$ 59,848	$ 50,003
Company's share of equity method investees' net capitalized costs	$ 1,067	$ --	$ --

Results of Operations

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

	2003	2002	2001
Revenues			
Sales	$43,458	$23,291	$30,150
Production costs	14,432	6,310	5,532
Depreciation, depletion & amortization and valuation provisions	9,331	7,246	7,381
	23,763	13,556	12,913
Income tax expenses	3,953	1,668	4,607
Results of operations from producing activities (excluding corporate overhead and interest costs)	$15,742	$ 8,067	$12,630
Company's share of equity method investees' results of operations for producing activities	$ 337	$ --	$ --

Standardized Measure of Discounted Future Net Cash Flows

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

	2003	2002	2001
Future cash inflows	$ 794,555	$ 274,900	$ 136,442
Future production and development costs	(339,732)	(124,451)	(70,671)
Future income tax expenses	(129,538)	(41,546)	(12,579)
Future net cash flows	325,285	108,903	53,192
10 percent annual discount for estimated timing of cash flows	(123,163)	(36,585)	(14,316)
Standardized measure of discounted future net cash flows	$ 202,122	$ 72,318	$ 38,876

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):

	2003	2002	2001
Sales and transfers of oil and gas produced, net of production costs	$(29,026)	$(16,981)	$(24,619)
Net changes in prices and production costs	51,735	33,285	(66,408)
Extensions, discoveries and improved recovery, less related costs	9,064	15,700	21,339
Development costs incurred during the period	32,757	2,202	2,704
Revisions of previous quantity estimates	26,632	11,839	(11,567)
Accretion of discount	9,417	4,375	11,145
Net change in income taxes	(41,372)	(16,978)	24,138
Purchases of reserves	70,597	--	9,700

(22) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following table sets forth selected unaudited historical operating results and market data for each quarter of 2003 and 2002.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2003				
Operating revenues	$ 291,445	$ 289,243	$ 410,862	$ 258,502
Operating income	35,919	34,704	39,898	26,236
Income from continuing operations before changes in accounting principles	15,666	13,963	17,641	9,725
Income from discontinued operations, net of taxes	1,192	2,697	4,803	730
Net income	14,178	16,660	22,444	7,940
Net income available for common stock	14,121	16,603	22,387	7,853
Earnings per common share:				
Basic -				
Continuing operations	$ 0.58	$ 0.45	$ 0.55	$ 0.30
Discontinued operations	0.04	0.09	0.15	0.02
Changes in accounting principles	(0.10)	--	--	(0.08)
Total	$ 0.52	$ 0.54	$ 0.70	$ 0.24
Diluted -				
Continuing operations	$ 0.57	$ 0.45	$ 0.54	$ 0.30
Discontinued operations	0.04	0.09	0.15	0.02
Changes in accounting principles	(0.09)	--	--	(0.08)
Total	$ 0.52	$ 0.54	$ 0.69	$ 0.24
Dividends paid per share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Common stock prices				
High	$ 28.39	$ 31.70	$ 33.54	$ 33.15
Low	$ 21.85	$ 27.00	$ 29.82	$ 27.76

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2002				
Operating revenues	$ 163,205	$ 250,413	$ 239,786	$ 255,087
Operating income	28,108	26,105	34,340	28,386
Income from continuing operations before changes in accounting principles	14,224	12,695	16,815	14,845
Income (loss) from discontinued operations, net of taxes	(1,054)	1,112	634	1,285
Net income	14,066	13,807	17,449	16,130
Net income available for common stock	14,008	13,751	17,393	16,077
Earnings per common share:				
Basic -				
Continuing operations	$ 0.53	$ 0.47	$ 0.63	$ 0.55
Discontinued operations	(0.04)	0.04	0.02	0.05
Changes in accounting principles	0.03	--	--	--
Total	$ 0.52	$ 0.51	$ 0.65	$ 0.60
Diluted -				
Continuing operations	$ 0.53	$ 0.47	$ 0.62	$ 0.54
Discontinued operations	(0.04)	0.04	0.02	0.05
Changes in accounting principles	0.03	--	--	--
Total	$ 0.52	$ 0.51	$ 0.64	$ 0.59
Dividends paid per share	$ 0.29	$ 0.29	$ 0.29	$ 0.29
Common stock prices				
High	$ 33.98	$ 36.90	$ 35.08	$ 27.75
Low	$ 26.01	$ 31.62	$ 23.03	$ 18.36

(23) SUBSEQUENT EVENTS

Cheyenne Transaction

On January 13, 2004, the Company entered into a Stock Purchase Agreement to acquire from Xcel Energy Inc. all of the outstanding capital stock of its subsidiary, Cheyenne Light, Fuel & Power Company (Cheyenne), a Wyoming corporation. Cheyenne owns and operates transmission and distribution facilities to provide electricity and natural gas to consumers in Laramie County, Wyoming. The consideration for the acquisition includes a cash payment plus assumption of outstanding debt of Cheyenne. The acquisition, which is subject to federal and state regulatory approvals, is expected to close prior to December 31, 2004.

Debt Repayment

On January 30, 2004, the Company repaid $45 million of the long-term debt outstanding on the Fountain Valley project.

Las Vegas Cogeneration II Power Sales Agreement with Nevada Power Company

On March 3, 2004, the Public Utilities Commission of Nevada approved a long-term tolling contract to provide capacity and energy from the Las Vegas II power plant to NPC, a subsidiary of Sierra Pacific Resources.

The contract becomes effective April 1, 2004 and expires December 31, 2013. The contract is a tolling arrangement whereby NPC is responsible for supplying natural gas. The Las Vegas II power plant, comprised of combined-cycle gas turbines, is rated at 224 megawatts. The power plant's capacity and energy will be fully dispatchable by NPC to serve its retail load.

Black Hills Nevada, LLC, a subsidiary of the Company, has guaranteed the performance of Las Vegas Cogeneration II LLC under the contract up to $5 million. The Company's guarantee to Sempra Energy Solutions in the amount of $10 million, as shown in the Guarantee Table in Note 5, will be terminated before the April 1, 2004 Nevada Power contract commencement date.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of 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, 2003. Based on their evaluation, they have concluded that our disclosure controls and procedures are adequate and effective to ensure that material information relating to us that is required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the required time periods.

Changes in internal control over financial reporting

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.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding our directors and information required by Items 401, 405 and 406 of Regulation S-K are incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 26, 2004.

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

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

ITEM 11. EXECUTIVE COMPENSATION

Information regarding management remuneration and transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 26, 2004.

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

Information regarding the security ownership of certain beneficial owners and management is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 26, 2004.

The following table includes information as of December 31, 2003 with respect to our equity compensation plans. These plans include the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Compensation Plan, the Employee Stock Purchase Plan, the Outside Directors Stock Based Compensation Plan and the Short-term Annual Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders(1)	1,227,904	$ 27.67	667,598(2)
Equity compensation plans not approved by security holders(3)	26,599(4)		141,591(5)
Total	1,254,503		809,189

(1) Consists of the 1996 Stock Option Plan, the 1999 Stock Option Plan, the 2001 Omnibus Incentive Plan and the Employee Stock Purchase Plan. At December 31, 2003, the Employee Stock Purchase Plan had 16,782 shares subscribed to (which are reflected in column (a)) at a price of $28.59 per share and 118,567 shares available for future issuance (which are reflected in column (c)).

(2) 118,567 shares are available for future issuance under the Employee Stock Purchase Plan, 39,054 shares are available for issuance under the 1996 and 1999 Stock Option Plans and 509,977 shares are available for issuance under the 2001 Omnibus Incentive Compensation Plan. Shares under the 2001 Omnibus Incentive Compensation Plan may be issued in connection with stock options, stock appreciation rights, restricted stock (limited to 140,225 shares), performance shares, performance units and cash-based awards.

(3) Consists of the Outside Directors Stock Based Compensation Plan and the Short-term Annual Incentive Plan.

(4) Represents common stock equivalents under the Outside Directors Stock Based Compensation Plan, of which there is no exercise price.

(5) Represents shares available for issuance under the Short-term Annual Incentive Plan.

The following two equity compensation plans have not been approved by our shareholders.

Outside Directors Stock Based Compensation Plan

The Outside Directors Stock Based Compensation Plan was adopted by us effective January 1, 1997. The purpose of the plan is to provide to outside directors certain benefits in order to attract and retain competent and hardworking individuals whose abilities, experience and judgment can contribute to our well-being and the well-being of our shareholders and to further align the long-term interests of our outside directors with those of our shareholders by paying a portion of board compensation in the form of Company common stock equivalents. Each outside director receives a monthly addition to their common stock equivalent memorandum account (Account) in the amount of the number of Company common stock equivalents determined by dividing their monthly benefit (currently $1,250) by the market price of the Company's common stock on the last day of the month. At the time an outside director becomes a participant in the plan, the director makes an election designating the age benefit payments are to begin (Benefit Payment Date) and whether they want to take the benefit payments in cash or in Company common stock. If the director elects to have the benefit paid in cash, the value is calculated by multiplying the number of common stock equivalents in the director's Account by the market value of the Company's common stock on the Benefit Payment Date. If the director elects to have the benefit paid in Company common stock, the director will receive shares of Company common stock equal to the number of common stock equivalents in the director's Account.

Short-term Annual Incentive Plan

The Short-term Annual Incentive Plan was adopted by the Board of Directors, effective January 1, 1998, to attract and keep in our employ persons of experience and ability by providing additional incentives to those who contribute significantly to the successful and profitable operation of the business and affairs of our company and its subsidiaries. The plan provides an opportunity for these employees to participate in the successful results of operations through awards, granted on a merit basis. Employees eligible to participate in the plan are the officers of the Company, of whom the Compensation Committee of the Board of Directors (the Committee) shall annually designate to participate in the plan for that year. Each participant is assigned a target incentive award determined as a percent of the participant's base salary. In determining the target incentive award for each participant, the Committee considers the positions and responsibilities of the participant, the participant's accomplishments during the year, the value of such accomplishments to the Company and such other factors as the Committee deems pertinent. Each participant has the opportunity to earn various percentages of the target incentive award. The percentage of the target incentive award to be earned by each participant is determined by the application of objective performance measurements determined by the Committee, such as earnings per share. The application of the participant's target incentive award to actual performance results creates the actual award for each participant. The Board of Directors may require a portion or all of the incentive award paid to participants to be in the form of our common stock. Stock utilized for any incentive award under the plan may be treasury shares, shares purchased on the open market or shares acquired through the optional cash payment feature of our dividend reinvestment plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement for the Annual Shareholders' Meeting to be held May 26, 2004.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is incorporated herein by reference to our Proxy Statement for the Annual Shareholder's Meeting to be held May 26, 2004

PART IV

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Black Hills Corporation
Rapid City, South Dakota

We have audited the consolidated financial statements of Black Hills Corporation and subsidiaries as of December 31, 2003 and 2002 and for each of the three years in the period ended December 31, 2003, and have issued our report thereon dated March 10, 2004, which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in the methods of accounting for asset retirement obligations, contracts involving energy trading and risk management activities, and the consolidation of variable interest entities in 2003 described in Note 1, and the change in the method of accounting for goodwill and other intangible assets in 2002 described in Note 1. Such consolidated financial statements and report are included elsewhere in this 2003 Annual Report on Form 10-K. Our audits also included the financial statement schedule of Black Hills Corporation and subsidiaries, listed in Item 15(a)(2). This financial statement schedule is the responsibility of the Corporation's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2004

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Consolidated Financial Statements

Financial statements required by Item 15 are listed in the index included in Item 8 of Part II.

2. Schedules

Schedule II – Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2003, 2002 and 2001.

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 the Company's consolidated financial statements and Notes thereto.

BLACK HILLS CORPORATION
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

		Additions			
Description	**Balance at beginning of year**	**Charged to costs and expenses**	**Other (a)**	**Deductions (b)**	**Balance a end of year**
			(In thousands)		
Allowance for doubtful accounts:					
2003	$ 3,226	$ 2,358	$ 2,810	$ (1,049)	$ 7,345
2002	5,202	748	(823)	(1,901)	3,226
2001	3,510	2,675	(44)	(939)	5,202

(a) Recoveries

(b) Uncollectible accounts written off

3. Exhibits

Exhibit Number	Description
2.1*	Plan of Exchange Between Black Hills Corporation and Black Hills Holding Corporation (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
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10.21*	Multi-year Credit Agreement dated as of August 21, 2003 among Black Hills Corporation, as Borrower, The Financial Institutions party, hereto, as Banks, ABN AMRO BANK N.A., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent, BMO Nesbitt Burns Financing, Inc., as Co-Syndication Agent, US Bank, National Association, as Documentation Agent, and The Bank of Nova Scotia, as Co-Documentation Agent (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2003).
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21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors' Consent.
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31.1	Certification pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
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32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

+ Indicates a board of director or management compensatory plan.

(b) Reports on Form 8-K

We have filed or furnished the following Reports on Form 8-K during the fourth quarter of our fiscal year ended December 31, 2003:

Form 8-K dated October 1, 2003.

Reported under Item 5 that the Company issued a press release announcing the sale of its ownership interests in seven hydroelectric power plants to affiliates of Boralex, Inc. and under Item 7, Exhibits.

Form 8-K dated October 30, 2003.

Reported under Item 12 that the Company issued a press release announcing quarterly results for the quarter ended September 30, 2003.

Form 8-K dated December 16, 2003.

Reported under Item 12 that the Company issued a press release updating its earnings outlook for the fourth quarter of 2003 and the year 2004, and under Item 7, Exhibits.

(c) See (a) 3. Exhibits above.

(d) 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, President
and Chief Executive Officer

Dated: March 15, 2004

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, President and Chief Executive Officer	Director and Principal Executive Officer	March 15, 2004
/S/ MARK T. THIES Mark T. Thies, Executive Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	March 15, 2004
/S/ DANIEL P. LANDGUTH Daniel P. Landguth, Chairman	Director and Officer	March 15, 2004
/S/ BRUCE B. BRUNDAGE Bruce B. Brundage	Director	March 15, 2004
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 15, 2004
/S/ JOHN R. HOWARD John R. Howard	Director	March 15, 2004
/S/ EVERETT E. HOYT Everett E. Hoyt, Chief Operating Officer	Director and Officer	March 15, 2004
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 15, 2004
/S/ RICHARD KORPAN Richard Korpan	Director	March 15, 2004
/S/ STEPHEN D. NEWLIN Stephen D. Newlin	Director	March 15, 2004
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 15, 2004

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FIRST AMENDMENT TO THE
BLACK HILLS CORPORATION
NONQUALIFIED DEFERRED COMPENSATION PLAN

Pursuant to Section 13.1 of the Black Hills Corporation Nonqualified Deferred Compensation Plan (the “Plan”), the Company (as defined in the Plan) hereby amends the Plan as follows:

1. Paragraph 2 of the Plan shall be amended by adding the following new subsection (p) and by relettering the current subsection (p) to subsection (q):

   (p) “RSU Contribution” means a Participant’s restricted stock unit award under the Company’s Omnibus Incentive Compensation Plan (the “Omnibus Plan”) or any successor plan that the Participant has deferred pursuant to the terms of the restricted stock unit agreement between the Participant and the Company (the “RSU Agreement”) and under subparagraph 4.3.

2. Paragraph 4 of the Plan shall be amended by adding the following new subparagraph 4.3:

   4.3 RSU Contributions. A Participant who has been granted and accepted an award in the form of restricted stock units under the Omnibus Plan must defer the receipt of the Participant’s entire award thereunder as an RSU Contribution. The amount of the award deferred under the Omnibus Plan and RSU Agreement shall be allocated to a Participant’s Account upon receipt by the Company of the Participant’s executed RSU Agreement. If the Participant does not vest in the award under the terms of the RSU Agreement, the deferral of the RSU Contribution shall be null and void. The Company shall establish within the Participant’s Account a Stock Account for the RSU contribution (as defined in subparagraph 4.2) and shall credit the Stock Account with Company common stock equivalents (but not actual shares), including fractional equivalents. Appropriate adjustments shall be made to the Stock Account for Stock splits, stock dividends, mergers, consolidation and other similar circumstances affecting the Company common stock. A Participant’s RSU Contributions shall remain subject to, and shall vest in accordance with, the terms of the applicable RSU Agreement.

3. Paragraph 5 shall be amended by adding the following new sentence as the final sentence thereto:

   RSU Contributions shall remain in Company Stock equivalents until distribution.

4. Paragraph 6 shall be amended by adding the following new sentence as the second sentence thereto:

   The amount in the Participant’s Account shall be paid in cash, except that any amounts in the Participant’s Stock Account attributable to Incentive Contributions or RSU Contributions shall be paid in the form of shares of Company Common Stock.

The effective date of this Amendment shall be April 29, 2003. Except for the Amendment above, the Plan shall remain in full force and effect.

Black Hills Corporation

By: Steven J. Helmers

Title: Sr. Vice President, General Counsel and Secretary

FIRST AMENDMENT TO THE
OUTSIDE DIRECTORS STOCK BASED COMPENSATION PLAN

This First Amendment to the Outside Directors Stock Based Compensation Plan ("Amendment") is adopted by Black Hills Corporation ("Company") effective the 1st day of June, 1999.

1. <u>RECITALS.</u>

This document is the First Amendment to the Outside Directors Stock Based Compensation Plan which was adopted by the Company effective the 1st day of January, 1997 (“Plan”). Under Section 10 of the Plan, Company reserved the right to amend, modify, or discontinue the Plan provided only that any modification is not to reduce accrued and unpaid benefits. The amendments hereunder do not reduce any accrued and unpaid benefits. At the time of this Amendment, none of the Participants are yet entitled to receive any benefits under the Plan. By their signatures below, the outside directors hereby agree to this Amendment and to the change in the time and manner of benefit payments provided and other changes made herein.

2. <u>AMENDMENT TO SECTION 4; PROVISION OF ADDITIONAL ANNUAL BENEFITS</u>.

Section 4 of the Plan is amended by adding the following subparagraph d:

> d. Beginning with June 1, 1999, and for the remainder of the 1999 Plan year, and for each Plan year thereafter, each Participant shall be entitled to a monthly addition to their Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $583.33 by the market price of the Company common stock on the last day of the month for each month of each Plan year that the Participant is eligible for benefits.

3. AMENDMENT TO SECTION 5.

Section 5 of the Plan entitled “Time and Manner of Benefit Payments” is amended and superseded in its entirety and in its place is hereby substituted the following:

5. TIME AND MANNER OF BENEFIT PAYMENTS.

a. Within 30 days of the effective date of this Amendment, each current Participant shall elect, on an election form to be filed with the Committee, a date (“Benefit Payment Date”), which shall be the date that benefit payments due hereunder are determined; provided, that no Benefit Payment Date for any Participant shall be earlier than the date that a Participant is 60 years of age nor shall any Benefit Payment Date be effective while any Participant is still an outside director of the Company; rather, such Benefit Payment Date shall only become effective on the first day that the Participant is no longer an outside director of the Company. Provided further still, that no Benefit Payment Date shall be later than the date that a Participant is 70 years of age. Newly eligible Participants shall make the same election within 30 days of becoming eligible under the Plan.

b. On the same election form, the Participant shall elect to receive payment of the benefits represented in the Participant’s Account from the following choices:

(1) A lump sum payment in cash in an amount equal to the Participant’s Account determined as of the Benefit Date due 30 days after the Benefit Payment Date;

(2) Payment of shares of common stock of the Company equal to the number of shares of Company common stock equivalents credited to the Participant’s Account determined as of the Benefit Payment Date due 30 days after the Benefit Payment Date; or

(3) Payment in monthly installments of cash over a period of not more than 15 years, the first installment being due 30 days after the Benefit Payment Date. The installment pay out period shall be specified in the election. The amount of each installment shall equal the balance of the Participant's Account immediately prior to the installment divided by the number of installments remaining to be paid. After the first installment has been paid, the unpaid Account balance shall accrue interest at an annual rate equal to the United States Treasury Bond yield determined as of the Benefit Payment Date.

c. The Benefit Payment Date, once selected by a Participant, shall be irrevocable. The payment election, once made, may only be changed by the Participant's giving written notice to the Committee of the Participant's election to change the payment method and filing such election to change with the Committee; provided, however, that such request shall not become effective until the Plan year subsequent to the Plan year in which the request is made; and provided further still, that once payments have begun, the payment election shall be irrevocable.

d. Notwithstanding anything contained above, in the event of an Unforeseeable Emergency as hereinafter defined, a Participant may withdraw amounts from the Participant's account to the extent reasonably needed to satisfy the Unforeseeable Emergency. For the purposes of this paragraph, an "Unforeseeable Emergency" is a severe financial hardship to the Participant resulting from a sudden and unexpected illness or accident of the Participant or a dependent (as defined in Internal Revenue Code Section 152(a)) of the Participant, loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. The circumstances that will constitute an Unforeseeable Emergency will depend upon the facts of each case, but, in any case, payment may not be made to the extent that such hardship is or may be relieved — (a) through reimbursement or compensation by insurance or otherwise; (b) by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship. Examples of what are not considered to be an Unforeseeable Emergency include the need to send a Participant's child to college or the desire to purchase a home.

4. AMENDMENT TO SECTION 8.

Section 8 of the Plan entitled “Designation of Beneficiary” is amended to add the following sentence: The Participant shall have the right, without the requirement of approval from any person, to revoke and change Beneficiary designations.

5. NO OTHER CHANGES.

Other than specifically set forth herein, all terms, conditions and provisions of the Plan shall remain the same.

Dated this 1st day of June, 1999.

BLACK HILLS CORPORATION

By /S/ DANIEL P. LANDGUTH
Its

ATTEST:

/S/ ROXANN R. BASHAM
Secretary and Treasurer

(CORPORATE SEAL)

OUTSIDE DIRECTORS:

/S/ ADIL M. AMEER
Adil M. Ameer

/S/ GLENN C. BARBER
Glenn C. Barber

/S/ BRUCE B. BRUNDAGE
Bruce B. Brundage

/S/ JOHN R. HOWARD
John R. Howard

/S/ KAY S. JORGENSEN
Kay S. Jorgensen

/S/ THOMAS J. ZELLER
Thomas J. Zeller

/S/ DAVID C. EBERTZ
David C. Ebertz

Exhibit 10.14

SECOND AMENDMENT TO THE OUTSIDE DIRECTORS STOCK BASED COMPENSATION PLAN

This Second Amendment to the Outside Directors Stock Based Compensation Plan ("Amendment") is adopted by Black Hills Corporation ("Company") effective the 1st day of May, 2002.

1. RECITALS.

This document is the Second Amendment to the Outside Directors Stock Based Compensation Plan which was adopted by the Company effective the 1st day of January, 1997 ("Plan"). Under Section 10 of the Plan, the Company reserved the right to amend, modify, or discontinue the Plan provided only that any modification is not to reduce accrued and unpaid benefits. The amendment hereunder does not reduce any accrued or unpaid benefits.

2. AMENDMENTS TO SECTION 4; PROVISION OF ADDITIONAL ANNUAL BENEFITS.

Section 4 of the Plan is amended by adding the following e:

e. Beginning with May 1, 2002, and for the remainder of the 2002 Plan year, and for each Plan year thereafter, each Participant shall be entitled to a monthly addition to their Account in the amount of the number of Company common stock equivalents determined by dividing the sum of $1,250.00 by the market price of the Company common stock on the last day of the month for each month of the Plan year that the Participant is eligible for benefits.

3. NO OTHER CHANGES.

Other than specifically set forth herein, all terms, conditions and provisions of the Plan shall remain the same.

Dated this 1st day of May, 2002.

BLACK HILLS CORPORATION

By /s/ Daniel P. Landguth
Its Chairman and CEO

ATTEST:

/s/ Steven J. Helmers
Secretary

(CORPORATE SEAL)

BLACK HILLS CORPORATION

ACTIVE WHOLLY OWNED DIRECT AND INDIRECT SUBSIDIARIES

Acquisition Partners, LP, a New York limited partnership

Adirondack Hydro Development Corporation, a Delaware corporation

Black Hills Cabrestro Pipeline, LLC, a Delaware limited liability company

Black Hills Colorado, LLC, a Delaware corporation

Black Hills Energy, Inc., a South Dakota corporation

Black Hills Energy Pipeline, LLC, a Delaware limited liability company

Black Hills Energy Resources, Inc., a South Dakota corporation

Black Hills Energy Terminal, LLC, a South Dakota limited liability company

Black Hills Exploration and Production, Inc., a Wyoming corporation

BHFC Publishing, LLC, a Delaware limited liability company

Black Hills FiberCom, LLC, a South Dakota corporation

Black Hills Fiber Systems, Inc., a South Dakota corporation

Black Hills Fountain Valley, LLC, a Delaware limited liability company

Black Hills Fountain Valley II, LLC, a Colorado limited liability company

Black Hills Generation, Inc., a Delaware corporation

Black Hills Harbor, LLC, a Delaware limited liability company

Black Hills Idaho Operations, LLC, a Delaware limited liability company

Black Hills Kilgore Energy Pipeline, LLC, a Delaware limited liability company

Black Hills Kilgore Pipeline Company, L.P., a Texas limited partnership

Black Hills Kilgore Pipeline, Inc., a Delaware corporation

Black Hills Long Beach, Inc., A Delaware corporation

Black Hills Millennium Pipeline, Inc., a South Dakota corporation

Black Hills Millennium Terminal, Inc., a South Dakota corporation

Black Hills Nevada, LLC, a Delaware limited liability company

Black Hills Nevada Operations, LLC, a Delaware limited liability company

Black Hills Nevada Real Estate Holdings, LLC, a Delaware limited liability company

Black Hills North America, Inc., a Delaware corporation

Black Hills Ontario, LLC, a Delaware limited liability company

Black Hills Operating Company, LLC, a Delaware limited liability company

Black Hills Power, Inc., South Dakota corporation

Black Hills Publishing Montana, LLC, a Delaware limited liability company

Black Hills Southwest, LLC, a Delaware limited liability company

Black Hills Valmont Colorado, Inc., a Delaware corporation

Black Hills Wyoming, Inc., a Wyoming corporation

Daksoft, Inc., a South Dakota corporation

E-Next A Equipment Leasing Company, LLC, a Delaware limited liability company

EIF Investors, Inc., a Delaware corporation

Enserco Energy, Inc., a South Dakota corporation

Fountain Valley Power, LLC, a Delaware limited liability company

Harbor Cogeneration Company, a California general partnership

Indeck North American Power Fund, LP, a Delaware limited liability company

Indeck North American Power Partners, LP, a Delaware limited liability company

Indeck Pepperell Power Associates, Inc., a Delaware corporation

Landrica Development Company, a South Dakota corporation

Las Vegas Cogeneration II, LLC, a Delaware limited liability company

Las Vegas Cogeneration Energy Financing Company, LLC, a Delaware limited liability company

Mallon Oil Company, a Colorado corporation

Mallon Resources Corporation, a Colorado corporation

Millennium Pipeline Company, L.P., a Texas limited partnership

Millennium Terminal Company, L.P., a Texas limited partnership

NHP, LP, a New York limited partnership

North American Funding, LLC, a Delaware limited liability company

Sunco Ltd., a Nevada limited liability company

Wyodak Resources Development Corp., a Delaware corporation

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Amendment No. 1 to Registration Statement No. 333-101541 and Registration Statement No. 33-71130 on Form S-3 and Registration Statement Nos. 33-63059, 333-61969, 333-17451, 333-82787, 333-30272, and 333-63264 on Form S-8 of Black Hills Corporation of our report dated March 10, 2004 (which reports express unqualified opinions and include an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, and Emerging Issues Task Force Issue 02-3, *Accounting for Contracts Involving Energy Trading and Risk Management Activities*, effective January 1, 2003, Financial Accounting Standards Board Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities*, effective December 31, 2003, and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*) appearing in this Annual Report on Form 10-K of Black Hills Corporation for the year ended December 31, 2003.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2004

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEER AND GEOLOGIST

As petroleum engineers, we hereby consent to the inclusion of the information included in this Form 10-K with respect to the oil and gas reserves of Black Hills Exploration and Production, Inc., the future net revenues from such reserves, and the present value thereof, which information has been included in this Form 10-K in reliance upon the report of this firm and upon the authority of this firm as experts in petroleum engineering. We hereby further consent to all references to our firm included in this Form 10-K and to the incorporation by reference in the Registration Statements on Form S-8 Nos. 33-63059, 333-61969, 333-17451, 333-82787, 333-30272 and 333-63264 and the Registration Statements on Form S-3, Nos. 33-71130 and 333-101541.

RALPH E. DAVIS ASSOCIATES, INC.

/s/ Ralph E. Davis

March 12, 2004

CERTIFICATION

I, David R. Emery, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2004

/s/ David R. Emery
President and
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   a) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2004

/s/Mark T. Thies
Executive Vice President and
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David R. Emery, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2004

/s/ David R. Emery
David R. Emery
President and
Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Black Hills Corporation (the “Company”) on Form 10-K for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark T. Thies, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13 (a) or 15 (d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2004

/s/Mark T. Thies
Mark T. Thies
Executive Vice President and
Chief Financial Officer