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, 2002

☐ 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 28, 2002	$734,526,500

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 28, 2003
Common stock, $1.00 par value	26,953,904 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 2003 Annual Meeting of Stockholders to be held on May 28, 2003, are incorporated by reference in Part III of the Form 10-K.

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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. Our regulated and unregulated businesses have expanded their asset bases significantly in recent years. Our integrated energy group produces and markets power and fuel and transports crude oil. We produce and sell electricity in a number of markets, with a strong emphasis on the western United States. We also produce coal, natural gas and crude oil primarily in the Rocky Mountain region and market fuel products primarily in the Rocky Mountain, western and mid-continent regions of the United States and in Western Canada. Our electric utility serves approximately 60,000 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communication services to residential and business customers in Rapid City and the northern Black Hills region of South Dakota. Our predecessor 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 integrated 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 last part of 2000 accounted for approximately $1.40 per share and $0.40 per share of our earnings in 2001 and 2000, respectively.

	2002	2001	2000	1999	1998
Net income available for common (in thousands):					
Integrated energy	$ 44,127	$ 57,930	$ 29,379	$ 12,554	$ 9,947
Electric utility	30,217	45,238	37,178	27,362	24,825
Communications	(7,260)	(12,300)	(11,382)	(968)	(280)
Corporate expenses and intersegment eliminations	(3,218)	(3,811)	(2,441)	(1,210)	121
Oil and gas write-down	--	--	--	--	(8,805)
Discontinued operations	(2,637)	493	36	(671)	--
	$ 61,229	$ 87,550	$ 52,770	$ 37,067	$ 25,808
Earnings per share - diluted	$ 2.26	$ 3.42	$ 2.37	$ 1.73	$ 1.19(2)
Total assets (in thousands)	$2,035,169	$1,662,401	$1,320,320	$ 668,492	$ 559,417
Capital expenditures (in thousands)	$ 303,918	$ 594,142	$ 173,517(1)	$ 152,948	$ 27,225
Generating capacity (megawatts)					
Utility (owned generation)	435	395	393	353	353
Utility (purchased capacity)	60	65	70	75	75
Independent power generation	950(3)	617	250	--	--
Total generating capacity	1,445	1,077	713	428	428
Utility electric sales (megawatt-hours):					
Firm electric sales	1,966,060	2,012,354	1,973,066	1,920,005	1,923,331
Wholesale off-system	979,677	965,030	684,378	445,712	371,104
Total utility electric sales	2,945,737	2,977,384	2,657,444	2,365,717	2,294,435
Oil and gas reserves (Mmcfe)	57,793	48,401	44,882	44,114	30,160
Oil and gas production sold (Mmcfe)	7,398	7,293	5,278	4,698	4,120
Tons of coal sold (thousands of tons)	4,052	3,518	3,050	3,180	3,280
Average daily marketing volumes:					
Natural gas (MMbtus)	1,088,200	1,047,700	860,800	635,500	524,800
Crude oil (barrels)	57,200	36,500	44,300	19,270	19,000
Communications:					
Residential customers	21,700	15,660	8,368	143	--
Business customers	3,061	2,250	646	110	--
Fiber optic backbone miles	242	242	210	200	--
Hybrid fiber coaxial cable miles	818	737	588	100	--

(1) Excludes the non-cash acquisition of Indeck Capital, Inc.

(2) Includes impact of $(0.41) per share non-cash write-down of oil and gas properties due to historically low oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

(3) Includes the 224 megawatt expansion at the Las Vegas cogeneration power plant that was placed in service on January 3, 2003.

For additional information on our business segments see – ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 16 of NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

Industry Overview

The energy and telecommunications industries can be 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 markets as a result of the 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 and the current recession mitigated most regional energy shortages.

The energy industry recently faced a financial crisis stemming from the loss of billions of dollars in market capitalization reflecting broad market conditions and investor attitudes. Investors and consumers have lost confidence in the financial health of many energy providers as a result of numerous events following the collapse of Enron. Accordingly, energy companies have been subject to much greater scrutiny and significantly tighter credit standards. Companies are moving aggressively to improve liquidity and to restructure their balance sheets. They are selling non-core assets, downsizing, 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 assets.

The oil and gas industry has experienced volatile changes in commodity prices in recent years. Price increases were driven in part by several years of modest drilling activity combined with strong growth in demand for energy commodities and the threat of war in the Middle East. Price decreases were driven by weather patterns, the recession and actions by OPEC. Natural gas is expected to remain the fuel of choice. Demand for natural gas is expected to be strong in the future as an increasing number of 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, the 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 telecommunication market. More recently the telecommunication industry suffered the effects of an economic slowdown, increased competition and financial stress.

Our Business Strategy

Our long-term growth strategy is to add and augment revenue streams from our diverse integrated 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 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 growth objectives. This diversity provides 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 production from new independent power projects through 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 retail customers while retaining the flexibility to allocate excess generating capacity to maximize returns in changing market environments;
- increase our reserves of natural gas and crude oil and expand our fuel production;
- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure;
- conduct business with a diversified group of creditworthy counterparties;
- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;
- 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 strong “super local” service company by capitalizing on our utility’s established market presence, relationships and customer loyalty to expand our local communications business, integrating our electric and telecommunications products around the same customer base; and
- organize our lines of business into retail and wholesale energy components. The retail component will consist of electric and telecommunications products in the same footprint as our electric utility exists today. 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 the 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 will continue, thereby creating opportunities for 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 share infrastructure with existing facilities at the same site.

We recently expanded our capacity with brownfield development at our Arapahoe and Las Vegas sites and are currently expanding our Wyodak site. 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 Production From New Independent Power Projects Through 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. Approximately 90 percent of our unregulated power generation assets are under long-term contracts.

Preserve our Electric Utility’s Low-Cost Rate Structure for our Retail Customers While Retaining the Flexibility to Allocate Excess Generating Capacity 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.

Increase our Reserves of Natural Gas and Crude Oil and Expand our Fuel Production. We aim to support the fuel requirements of our growing portfolio of power plants as well as power plants owned by others by emphasizing natural gas. 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 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.

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 Counterparties. Our operations require effective management of counterparty credit risk. We mitigate this risk by conducting business with a diversified group of creditworthy counterparties. 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 Remain a Low-Cost Power Producer. 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 to achieve very low production costs, especially at our coal-fired and hydroelectric generating facilities.

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, such as the Wygen plant, which went into service in the first quarter 2003; and
- pursue future sales of coal from the Wyodak mine to 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 Strong "Super Local" Service Company by Capitalizing on our Utility's Established Market Presence, Relationships and Customer Loyalty to Expand our Local Communications Business, Integrating our Electric and Telecommunications Products Around the Same Customer Base. As a result of its firmly established market presence, our electric utility has built solid brand recognition and customer loyalty in the Black Hills region. By ensuring a reliable supply of power to retail customers in our South Dakota and Wyoming service territory at rates below the national average, we have developed a strong, supportive relationship with our utility regulators. Our utility provides a solid foundation of support for the expansion of our communications businesses. In addition, technical and market expertise from our utility and our strong brand recognition promotes rapid customer acceptance of our bundled communications services in our Black Hills service territory.

Integrated Energy

Our integrated 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 integrated 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 and expands unregulated power plants. We hold varying interests in independent power plants in California, New York, Massachusetts, Wyoming, Nevada and Colorado with a total net ownership of 950 megawatts in operation, including minority interests in several power-related funds with a net ownership interest of 24 megawatts.

Project Development Program. At December 31, 2002, we were in the final stages of construction of the 90 megawatt coal-fired Wygen power plant at our Wyodak site located near Gillette, Wyoming. The Wygen plant became operational in the first quarter of 2003 and is accounted for as an operating lease.

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 with 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 (including plants currently operating and those under construction) is diversified in terms of fuel mix and geographic location, with 87 percent of net unregulated capacity being gas-fired, 9 percent coal-fired, and the remainder hydroelectric. Our independent power plants are located in California, Wyoming, Colorado, Nevada, New York and Massachusetts. 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. Currently, we sell approximately 90 percent of our unregulated generating capacity in operation under contracts greater than one year in duration. We sell the remainder of this capacity under short-term contracts or directly into the power markets. Substantially all of the energy and capacity generated by our Wygen plant is also under long-term contracts.

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 to counterparties with investment grade credit, while reserving the remainder for merchant or "spot" sales. 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 own approximately 845 megawatts of generating capacity in the WECC states of California, Colorado, Nevada and Wyoming, and at December 31, 2002, we were in the final stages of constructing another 90 megawatts in the region which became operational in the first quarter of 2003. All the facilities currently in operation are gas-fired, and the majority are operating under long-term power purchase or tolling agreements whereby the purchaser assumes the fuel price risk. The 90 megawatt plant under construction is coal-fired.

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
Gillette CT	Gas	WY	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
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 in Operation			877.0		844.5	
Under Construction:						
Wygen	Coal	WY	90.0	100%	90.0	2003
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 under tolling contracts expiring in 2012.

Las Vegas Cogeneration Facility. 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 generally accepted accounting principles, we consolidate 100 percent of the plant in our financial statements.

In late December 2002, we completed construction on Las Vegas II, a 224 megawatt gas-fired expansion of the Las Vegas Cogeneration Facility. We sell the power generated by Las Vegas II under a long-term contract with Allegheny Energy Supply L.L.C. that expires in 2018. We own 100 percent of Las Vegas II.

Gillette CT. The Gillette CT, a gas-fired combustion turbine located at the same site as our Wygen plant, has a total capacity of 40 megawatts and became operational in May 2001. We sell the energy and capacity from this facility to Cheyenne Light, Fuel and Power Company under a 10-year tolling agreement.

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. The Wygen plant is substantially identical in design to our Neil Simpson II facility, completed in 1995. The plant runs on pulverized low-sulfur coal fed by conveyor from our adjacent Wyodak mine. The plant will burn approximately 500,000 tons of coal per year, and was built with the latest available environmental control technology. The majority of the power from the facility is under long-term unit contingent capacity and energy sales contracts, under which delivery is not required during plant outages. We have contracts to sell 60 megawatts of unit contingent capacity from this plant to Cheyenne Light, Fuel and Power Company with a term of 10 years and 20 megawatts of unit contingent capacity and energy to the Municipal Energy Agency of Nebraska for a term of 10 years.

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 all of its steam production to Sunkist Growers, Inc. under a five-year agreement, which terminates in November 2007.

Harbor Cogeneration Facility. Harbor Cogeneration, a 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. During 2001, we completed an expansion of the Harbor Cogeneration plant adding 18 megawatts, and in 2002, we acquired the remaining ownership interest in this plant. In December 2002, we entered into a tolling agreement pursuant to which we will sell the peaking capacity for the summer periods from 2003 through 2007. We plan to sell the remaining capacity and energy from this plant in the California market on a merchant basis.

Northeast Facilities. We currently own approximately 82 net megawatts of generating capacity in eight plants in the Northeast region, all of which are located in New York and Massachusetts.

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Warrensburg	Hydro	NY	2.9	100.0%	2.9	1988
Middle Falls	Hydro	NY	2.3	50.0%	1.2	1989

New York State Dam	Hydro	NY	11.4	100.0%	11.4	1990
Sissonville	Hydro	NY	3.0	100.0%	3.0	1990
South Glens Falls	Hydro	NY	13.9	30.2%	4.2	1994
Hudson Falls	Hydro	NY	41.9	37.0%	15.5	1995
Fourth Branch	Hydro	NY	3.4	100.0%	3.4	1988
Pepperell	Gas	MA	40.0	100.0%	40.0	1990
Total Northeast			118.8		81.6	

Adirondack Hydro Development

The seven "run-of-river" hydroelectric plant interests are:

- New York State Dam, an 11.4 megawatt plant located in Waterford and Cohoes, New York;
- Middle Falls, a 2.3 megawatt plant located in Easton, New York;
- Sissonville, a 3.0 megawatt plant located in Potsdam, New York;
- Warrensburg, a 2.9 megawatt plant located in Warrensburg, New York;
- Hudson Falls, a 41.9 megawatt plant located in Moreau, New York;
- South Glens Falls, a 13.9 megawatt plant located in South Glens Falls, New York; and
- Fourth Branch, a 3.4 megawatt plant located in Waterford, New York.

The seven New York projects were initially covered by long-term power purchase contracts with Niagara Mohawk Power Corporation for all or most of their output. Niagara Mohawk bought out the power purchase contracts for the New York State Dam, Sissonville, Fourth Branch and Warrensburg facilities and the power from those projects is currently being sold into the New York Independent System Operator (ISO). The remaining three New York plants, Hudson Falls, South Glens Falls and Middle Falls, continue to operate under long-term power purchase agreements with Niagara Mohawk.

Pepperell Facility. The Pepperell facility is a 40 megawatt gas-fired combined-cycle plant located in Pepperell, Massachusetts. The plant sells merchant wholesale energy into the New England ISO.

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 24 megawatts.

Fund Name	Total Amount ($MM)	Left to be Funded ($MM)	Number of Plants	Total Capacity (MWs)	Interest	Net Capacity (MWs)
Energy Investors Fund I	$ 159.5	$ 0	5	76.0	12.6%	9.6
Energy Investors Fund II	$ 115.0	$ 0	5	66.6	6.9%	4.6
Project Finance Fund III	$ 101.0	$ 0	3	136.8	5.3%	7.3
Caribbean Basin	$ 75.0	$ 60	2	60.3	3.7%	2.2
Total Fund Interests				339.7		23.7

Natural Gas and Crude Oil Production

Our oil and gas exploration and production segment operates approximately 384 oil and gas wells, all of which are located in Wyoming, Colorado and Nebraska. The majority of these wells are in the Finn-Shurley Field area, located in Weston and Niobrara Counties in Wyoming. We also own a working interest in, but do not operate, an additional 440 wells located in California, Montana, Louisiana, Colorado, North Dakota, Texas, Wyoming, Oklahoma and offshore in the Gulf of Mexico. In addition, we have accumulated significant acreage in the Rocky Mountain region, which we plan to utilize for oil and gas exploration.

As of December 31, 2002, we held proved reserves of 4.9 million barrels of oil and 28.5 billion cubic feet of natural gas, with approximately 63 percent of current production consisting of natural gas.

In October 2002, we entered into a definitive merger agreement with Mallon Resources Corporation pursuant to which Mallon would become our wholly-owned subsidiary. Mallon is an independent energy company engaged in oil and natural gas exploration, development and production primarily in the San Juan Basin of New Mexico. The merger was completed on March 10, 2003. We expect the merger to double our existing oil and gas reserves on a BCFE , or billion cubic feet equivalent basis, and to increase our production by approximately 50 percent over current levels.

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 4.1 million tons of coal in 2002. 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, 2002, we had coal reserves of 272.8 million tons, enough to satisfy present contracts for approximately 60 years.

Substantially all of our coal production is currently sold under long-term contracts to Black Hills Power, Inc., our electric utility, and to PacifiCorp. We have an additional contract to provide approximately 500,000 tons of coal per year to the Wygen plant, which commenced operations in the first quarter of 2003. 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 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. 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, 2002 were approximately 1.1 million MMBtu, or British thermal units of gas and 57,000 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

Gas Marketing. 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 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.

Oil Marketing and Transportation. 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.

In July 2002, we purchased the 190-mile long 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 60,000 electric customers, with an electric transmission system of 447 miles of high voltage lines and 514 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 are 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, 2002 was comprised of 30 percent commercial, 24 percent residential, 17 percent contract wholesale, 15 percent wholesale off-system, 13 percent industrial and 1 percent municipal sales and other revenue. Approximately 70 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.
- 15 percent of our electric revenues for the year ended December 31, 2002 consisted of off-system and short-term contract wholesale sales. Although the demand for power in the western markets has eased from the record levels seen in the first half of 2001, we expect increases in the volume of our off-system sales in the future due to demand growth in the Rocky Mountain region and the availability of 40 megawatts of gas-fired generating capacity which we added in 2002.

- Our system is capable of connecting to either the eastern or western transmission systems, which provides us with access between the WECC region and the Mid-Continent Area Power Pool, or "MAPP" region. This allows us the opportunity to improve system reliability by adding voltage support and take advantage of power price differentials between the two electric grids. We are able to interconnect up to 80 megawatts of our generation into the MAPP. Alternatively, we can serve up to 80 megawatts of our load from the MAPP region. The available transmission capacity of the MAPP transmission system determines how much of this 80 megawatts can be served from the eastern interconnection. We are proceeding with the construction of an AC-DC-AC transmission tie which is expected to be completed in late third quarter, or early fourth quarter of 2003. The transmission tie will provide us with additional load support for our utility customers and increase our ability to buy or sell electric power.
- We have firm transmission access to deliver up to 55 megawatts of power on PacifiCorp's system to wholesale customers in the western region during 2003, scheduled to decline to 50 megawatts in 2004.

Power Sales Agreements

We sell approximately 46 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 Public Service Company of Colorado for a period through 2004. For the 10-year period beginning with the completion of the Wygen facility in 2003, our utility and our power generation segment will 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 55 megawatts of baseload power in 2003, which is scheduled to decline to 50 megawatts in 2004 and thereafter; 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
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 situated 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 a 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 air-cooled, coal-fired wholly owned 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 91.0 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 242-mile inter- and intra-city fiber optic network and currently operate 818 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, 2002, we were serving 21,700 residential customers and 3,061 business customers.

The construction of our initial infrastructure build-out, which covers Rapid City and the northern Black Hills region, was completed in 2002. Emphasis now will be focused on efficiencies, both internal to our communications group and those that can be realized through our strategy as a "super local" service company.

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 generally prohibit 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 Vice President-Risk is responsible for overseeing these functions.

We 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 respective 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 power plant 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 plants 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 exclusively engaged, 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. Absent a substantial restructuring of our business, it would be difficult for us to comply with PUHCA without a material adverse effect on our business.

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.

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 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, Arapahoe, Valmont, Fountain Valley, 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.

Our subsidiary, Black Hills Ontario, the operator of a 12 megawatt natural-gas fired cogeneration facility located in Ontario, California, projects that it will need to continue purchasing NOx allowances for all future compliance years. Annual purchases are anticipated to be approximately 30,000 allowances. There is currently significant volatility in the price and supply of Regional Clean Air Incentives Market (RECLAIM) NOx allowances; although the South Coast Air Quality Management District (SCAQMD) has proposed a revision to its regulations to stabilize the RECLAIM market, it is unclear whether these rules will mitigate Black Hills Ontario's potential exposure for its projected allowance shortfall. Accordingly, no assurance can be given at this time regarding whether RECLAIM NOx allowances will be available for purchase to allow Black Hills Ontario to comply with RECLAIM requirements for the year ended June 30, 2003, or, if allowances are available, as to the cost of those allowances.

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 approved 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. At the present time, the state of Wyoming is moving away from BART and is requesting legislative approval for an emissions trading program. Legislative approval will be followed by regulation development and therefore applicability and subsequent requirements are uncertain at this time. We are aware that currently, states 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 are in the process of or 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" 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 new source review requirements. No such proceedings have been initiated or requests for information issued with respect to any of our facilities, but there can be no assurance 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-fired and oil-fired electric power plants under Section 112 of the Clean Air Act. The EPA is committed to proposing a rule to regulate such emissions by no later than December 2003. Because we do not know what the EPA may require with respect to this issue, we are not able to 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 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. However, because of opposition to the treaty in the United States Senate, the Kyoto Protocol has not been submitted to the Senate for ratification. 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 the United States ratifies the Kyoto Protocol or we otherwise become subject to limitations on emissions of carbon dioxide from our 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. 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.

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 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 were 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 can give no assurance that pollution will not 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.

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 land quality permitting programs.

Based on extensive reclamation studies, we have accrued approximately $18.5 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 "North 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 and remediation efforts continue today and we continue to monitor the site. 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, no assurance can be given.

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;
- 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; 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, 2002, we had 840 employees, approximately 294 of whom are employed in our utility business, 253 of whom are employed in our integrated energy businesses, 233 of whom are employed in our communications business and 60 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 generation, distribution and energy marketing operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. In recent months, 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, Nevada Power Company and Allegheny Energy Supply Company (AESC), counterparties under power purchase agreements with our subsidiaries, have recently been downgraded by one or more rating agencies. The credit ratings of Nevada Power Company and AESC were 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, in which case we would sell the plant's power on a merchant basis.

We have substantial indebtedness, much of which is short-term. We will require significant amounts of debt or equity capital in order to refinance or repay maturing indebtedness as it becomes due and to grow our business. Our future access to these funds is not certain, and our inability to access funds in the future could adversely affect our liquidity and our ability to implement our business strategy.

As of December 31, 2002, we had total consolidated indebtedness of approximately $983 million, of which approximately $425 million will mature before December 31, 2004. Our substantial indebtedness may:

- limit our ability to borrow funds or increase the cost to borrow additional funds;
- hinder our ability to pay dividends at the current rate;
- require us to dedicate a substantial portion of our cash flow from operations to pay our debt, which would reduce funds available for us to finance our current operations and for our future business opportunities;
- have a negative impact on our credit ratings;

- increase our vulnerability to adverse economic and industry conditions;
- place us at a competitive disadvantage compared to competitors having less debt; or
- require us to sell assets in order to repay debt.

Some of our debt agreements contain restrictive covenants, including restrictive financial covenants pertaining to our recourse debt-to-capitalization ratio, fixed charge coverage ratio and total level of equity. If we fail to maintain these specified ratios and levels, our ability to borrow funds could be further limited. If our failure to maintain those ratios and levels were to persist, the creditors under those debt agreements could eventually require us to immediately repay the entire balance of those outstanding loans.

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. Any further reduction in our ratings by Moody's or Standard & Poor's Rating Service, 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.

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 $200 million three-year and $195 million 364-day revolving credit facilities, our $35 million term loan, our $50 million project credit agreement, and our $27.5 million and $4.5 million secured financings. A downgrade in our credit rating would also result in an increase in the operating lease costs related to our Wygen plant lease.

A downgrade could also result in our business counterparties requiring us to provide additional amounts of collateral under new transactions, particularly transactions pertaining to our energy marketing activities.

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 depends upon 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 or working capital.

Our utility is regulated by various state utility commissions which generally possess broad powers to ensure that the needs of the utility customers are being met. As a result of the energy crisis in California and the financial troubles at a number of energy companies, some state utility commissions may seek to impose restrictions on the ability of our utility subsidiary to pay dividends or make advances to us. If successful, this could materially and adversely affect our ability to meet our financial obligations.

Geopolitical tensions, including the armed conflict in Iraq, may impair our ability to raise capital and limit our growth.

An extended conflict with Iraq or an increase in tensions with the government of North Korea could temporarily 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 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.

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 wholesale electricity and natural gas sales into a robust market. The prices of energy products in the wholesale power markets have declined significantly since 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;
- changes in federal or state laws and regulations;
- our inability to negotiate acceptable acquisition, construction, fuel supply or other material agreements;
- our inability to obtain financing on acceptable terms;
- 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 the estimates in our reported reserves. 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.

One of our subsidiaries may incur material liabilities due to a prior owner's potential violation of regulations for "qualifying facilities" under PURPA.

In August 2001, we purchased a partnership interest in the 53 megawatt Las Vegas Cogeneration Facility from an affiliate of Enron. The partnership is called Las Vegas Cogeneration, L.P. 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 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 Nevada Power Company 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.

Recently FERC issued an order announcing an investigation to determine whether Enron's ownership of the Las Vegas Cogeneration Facility violated the qualifying facility regulations under PURPA. In addition, the SEC recently issued an initial decision concluding that Enron is an electric utility and is thus not exempt from regulations under 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 does 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 rules with respect to the Las Vegas Cogeneration Facility, we, as a partner in the entity that now owns that facility, could be liable for any refunds, fines or other penalties FERC imposes. We could also be subject to additional liabilities resulting from third party claims. We have the right to seek indemnification from the prior owner. While the prior owner does not appear among the Enron subsidiaries and affiliates currently in bankruptcy, the Enron bankruptcy could impair our ability to enforce a claim for indemnification. Because FERC has only recently begun its investigation, we cannot predict the outcome of FERC's investigation.

We face potential claims related to forest fires in South Dakota in 2001 and 2002.

In September 2001 a fire occurred in the southwestern Black Hills. It is alleged that the fire occurred when a high voltage electrical span maintained by our electric utility subsidiary 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 us 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 injury to timber, fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. It is expected that substantially similar claims will be asserted against us by the United States Forest Service. Our investigation into the cause and origin of the fire is still pending. The total amount of damages claimed by the State of South Dakota is not specified in the complaint. We have denied all claims and will vigorously defend this matter.

In June 2002, the Grizzly Gulch forest fire damaged approximately 11,000 acres of private and governmental land located near Deadwood and Lead, South Dakota. The fire destroyed approximately 20 structures and caused the evacuation of the cities of Lead and Deadwood for approximately 48 hours.

The cause of the Grizzly Gulch fire was investigated by the State of South Dakota. Alleged contact between power lines owned by our electric utility subsidiary and undergrowth was implicated as the cause. We have initiated our own investigation into the cause of the fire, including the hiring of expert fire investigators and that investigation is continuing.

We have been notified of potential private civil claims for property damage and business loss. In addition, the State of South Dakota initiated a civil action in the Seventh Judicial Circuit Court, Pennington County, South Dakota, seeking recovery of damages for fire suppression, reclamation and remediation costs, and treble damages for injury to trees. The United States government initiated a civil action in U.S. District Court, District of South Dakota, asserting similar claims. Neither the State of South Dakota nor the United States specified the amount of their alleged damages. If it is determined that power line contact was the cause of the fire and that we were negligent in the maintenance of those power lines, we could be liable for resultant damages.

Although we cannot predict the outcome of our investigations or the viability of potential claims based on information currently available, management believes that any such claims, if determined adversely to us, will not have a material adverse effect on 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.

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

Hell Canyon Fire

In September 2001 a fire occurred in the southwestern Black Hills. It is alleged that the fire occurred when a high voltage electrical span maintained by our electric utility subsidiary 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 the Company 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 injury to timber, fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. It is expected that substantially similar claims will be asserted against the Company by the United States Forest Service. Our investigation into the cause and origin of the fire is still pending. The total amount of damages claimed by the State of South Dakota is not specified in the complaint. We have denied all claims and will vigorously defend this matter the timing or outcome of which is uncertain.

Although we cannot predict the outcome of our investigation or the viability of potential claims based on information currently available, management believes that any such claims, if determined adversely to us, will not have a material adverse effect on our financial condition or results of operations.

Grizzly Gulch Fire

On June 29, 2002, a forest fire began near Deadwood, South Dakota. Before being contained more than eight days later, the fire consumed approximately 11,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 20 structures. 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 our electric utility subsidiary.

On September 6, 2002, the State of South Dakota commenced litigation against the Company, 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 is asserted with respect to the claim for injury to timber. The total amount of alleged damages is not specified.

On March 3, 2003, the United States of America filed a similar suit against the Company, in the United States District Court, District of South Dakota, Western Division. The federal government 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. The total amount of alleged federal damages is not specified.

We are completing our own investigation of the fire cause and origin and have requested access to the materials that form the basis for the assertions of state and federal fire investigators. Our investigation is not complete, but based on information currently available, we expect to deny all claims and vigorously defend any and all claims brought by governmental or private parties.

Although we cannot predict the outcome of our investigation or the viability of potential claims based on information currently available, management believes that any such claims, if determined adversely to us, will not have a material adverse effect on our financial condition or results of operations.

FERC Investigation

In August 2001, we purchased a partnership interest in the 53 megawatt Las Vegas I power plant from an affiliate of Enron. The partnership is called Las Vegas Cogeneration, L.P. 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 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 Nevada Power Company 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.

Recently 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 recently issued an initial decision concluding that Enron is an electric utility and is thus not exempt from regulations under 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 does not relate to the 224 megawatt gas-fired Las Vegas II power plant owned and operated by Las Vegas Cogeneration II, LLC and located on the same site in North Las Vegas, Nevada. This plant is not now, and never was certified as a qualifying facility under PURPA.

If FERC determines that Enron violated the qualifying facility rules with respect to the Las Vegas I plant, we, as a partner in the entity that now owns that plant, could be liable for any refunds, fines or other penalties FERC imposes. We could also be subject to additional liabilities resulting from third party claims. We have the right to seek indemnification from the prior owner. While the prior owner does not appear among the Enron subsidiaries and affiliates currently in bankruptcy, the Enron bankruptcy could impair our ability to enforce a claim for indemnification. Because FERC has only recently begun its investigation, we cannot predict the outcome of FERC's investigation. However, based upon information currently available, we do not believe that any refunds, fines or penalties resulting from the investigation will adversely affect our financial condition or results of operations.

Other Proceedings

We have received a request for information from the U.S. Commodity Futures Trading Commission (CFTC) relating to its industry-wide investigation of trading practices of energy and power marketing firms. We will provide information to the CFTC regarding our trading and trade reporting activities.

In addition to the above proceedings, we are involved in numerous legal proceedings, claims and litigation in the ordinary course of business. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect our consolidated financial position or results of operations.

There are currently no pending material legal proceedings to which an officer or director is a party or has a material interest, that is adverse to us or our subsidiaries. There are also no material administrative or judicial proceedings arising under environmental quality or civil rights statutes pending or known to be contemplated by governmental agencies to which we are or would be a party.

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 2002.

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, 2003, we had 5,350 common shareholders of record and approximately 16,000 beneficial owners, representing all 50 states, the District of Columbia and 8 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 2003 meeting, our board of directors raised the quarterly dividend to $0.30 per share, equivalent to an annual dividend of $1.20 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 $425 million and 50 percent of our aggregate consolidated net income since April 1, 2002.

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, 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

Year ended December 31, 2001	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.28	$ 0.28	$ 0.28	$ 0.28
Common stock prices				
High	$45.74	$58.50	$45.55	$34.20
Low	$31.00	$39.50	$27.76	$26.00

ITEM 6. SELECTED FINANCIAL DATA

Years ended December 31,	2002	2001	2000	1999	1998
TOTAL ASSETS (in thousands)	$2,035,169	$1,662,401	$1,320,320	$668,492	$559,417
PROPERTY AND INVESTMENTS (in thousands)					
Total property and investments	$1,890,266	$1,564,664	$1,072,013	$699,928	$619,549
Accumulated depreciation and depletion	414,003	328,325	277,797	245,992	229,942
Capital expenditures	303,918	594,142	173,517*	152,948	27,225
CAPITALIZATION (in thousands)					
Long-term debt, net of current maturities	$ 618,862	$ 415,798	$ 307,092	$160,700	$162,030
Preferred stock equity	5,549	5,549	4,000	--	--
Common stock equity	529,614	509,615	278,346	216,606	206,666

Total capitalization	$1,154,025	$ 930,962	$ 589,438	$377,306	$368,696
CAPITALIZATION RATIOS					
Long-term debt, net of current maturities	53.6%	44.7%	52.1%	42.6%	43.9%
Preferred stock equity	0.5	0.6	0.7	--	--
Common stock equity	45.9	54.7	47.2	57.4	56.1
Total	100.0%	100.0%	100.0%	100.0%	100.0%
TOTAL OPERATING REVENUES (in thousands)	$ 423,919	$ 461,938	$ 292,142	$185,287	$180,674
INCOME FROM CONTINUING OPERATIONS (in thousands)	$ 63,193	$ 87,584	$ 52,812	$ 37,738	$ 25,808**
DIVIDENDS PAID ON COMMON STOCK (in thousands)	$ 31,116	$ 28,517	$ 23,527	$ 22,602	$ 21,737
COMMON STOCK DATA (in thousands)					
Shares outstanding, average	26,803	25,374	22,118	21,445	21,623
Shares outstanding, average diluted	27,167	25,771	22,281	21,482	21,665
Shares outstanding, end of year	26,933	26,652	22,921	21,372	21,578
(in dollars)					
Basic earnings per average share -					
Continuing operations	$ 2.35	$ 3.43	$ 2.39	$ 1.76	$ 1.19
Discontinued operations	(0.10)	0.02	--	(0.03)	--
Change in accounting principle	0.03	--	--	--	--
Total	$ 2.28	$ 3.45	$ 2.39	$ 1.73	$ 1.19**
Diluted earnings per average share -					
Continuing operations	$ 2.33	$ 3.40	$ 2.37	$ 1.76	$ 1.19
Discontinued operations	(0.10)	0.02	--	(0.03)	--
Change in accounting principle	0.03	--	--	--	--
Total	$ 2.26	$ 3.42	$ 2.37	$ 1.73	$ 1.19**
Dividends paid per share	$ 1.16	$ 1.12	$ 1.08	$ 1.04	$ 1.00
Book value per share, end of year	$ 19.66	$ 19.12	$ 12.14	$ 10.14	$ 9.58
RETURN ON COMMON STOCK EQUITY (year-end)	11.6%	17.2%	19.0%	17.1%	12.5% **

*Excludes the non-cash acquisition of Indeck Capital, Inc.

**Includes impact of an $8.8 million, or 41 cents per average share, write-down of certain oil and gas properties

ITEM 7. 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 – integrated energy, electric utility and communications. Our unregulated and regulated businesses have expanded significantly in recent years. Our integrated 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. The integrated energy group consists of four segments: power generation, oil and gas exploration and production, coal mining and energy marketing and transportation. Our electric utility, Black Hills Power, Inc., generates, transmits and distributes electricity to approximately 60,000 customers in South Dakota, Wyoming and Montana. Our communications group provides broadband telecommunication services to over 24,700 residential and business customers in Rapid City and the northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

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

Our long-term growth strategy is to add and augment revenue streams from our diverse integrated 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 provides a measure of stability in volatile or cyclical periods.

Prospective Information

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, particularly in our integrated energy operations. We strongly believe that we are strategically positioned to take advantage of opportunities to acquire and develop energy assets consistent with our prudent investment criteria and consistent with a prudent capitalization 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 the generation capacity of our existing sites through a strategy known as “brownfield development;"
- sell a large percentage of our production from new independent power projects through 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 retail customers while retaining the flexibility to allocate excess generating capacity to maximize returns in changing market environments;
- increase our reserves of natural gas and crude oil and expand our fuel production;
- manage the risks inherent in energy marketing by maintaining position limits that minimize price risk exposure;
- conduct business with a diversified group of creditworthy counterparties;
- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;
- 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 strong “super local” service company by capitalizing on our utility’s established market presence, relationships and customer loyalty to expand our local communications business, integrating our electric and telecommunication products around the same customer base; and
- organize our lines of business into retail and wholesale energy components. The retail component will consist of electric and telecommunications products in the same footprint as our electric utility exists today. The wholesale component will consist of fuel production, marketing, mid-stream assets and power production facilities.

Our integrated energy group was our largest contributor to revenue and earnings in 2002 and 2001. We expect that earnings from this group over the next few years will be driven primarily by our continued expansion in the power generation and oil and gas production segments. In October 2002, we entered into a definitive merger agreement with Mallon Resources Corporation to acquire Mallon. Mallon is an energy company engaged in oil and natural gas exploration, development and production primarily in the San Juan Basin of New Mexico. The merger was completed in March 2003 and is expected to double our oil and gas reserves, and increase our production by approximately 50 percent over current levels. Although we believe our integrated energy group will continue to grow as our largest business group, we cannot predict the price environment, regulation or growth in the energy markets.

Our electric utility’s retail business remained healthy in 2002, even though two of our largest and oldest customers, the Homestake Mining Company and Federal Beef Processors, discontinued operations in 2002. We believe that our electric utility will produce modest growth in revenue, and absent unplanned plant outages, it will continue to produce modest growth in earnings for the next several years due to the extension of our electric utility’s rate freeze until January 1, 2005. (See Rate Regulation.) 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 in the western markets.

Although our broadband communications business significantly increased residential and business customers in 2002, we expect it will sustain approximately $3.5 to $4.0 million in net losses in 2003, with profitability expected in 2004. The recovery of capital investment and future profitability are dependent primarily on our ability to sustain our customer base and control expenses, 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. 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.

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:

	2002	2001	2000
Revenue:			
Integrated energy	54%	50%	38%
Electric utility	38	46	59
Communications	8	4	3
	100%	100%	100%

	2001	2000

	2002		
Income (loss) from continuing operations:			
Integrated energy	68%	66%	55%
Electric utility	48	51	70
Communications	(11)	(14)	(23)
Corporate	(5)	(3)	(2)
	100%	100%	100%

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. Results of operations have been restated to reflect the discontinued operations.

2002 Compared to 2001

Consolidated income from continuing operations for 2002 was $63.2 million, compared to $87.6 million in 2001, or $2.33 per share in 2002, compared to $3.40 per share in 2001. Income (loss) from discontinued operations was $(2.6) million or $(0.10) per share in 2002 compared to $0.5 million, or $0.02 per share, in 2001. This equates to an 11.6 percent and 17.2 percent return on year-end common equity in 2002 and 2001, 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.

Consolidated revenues were $423.9 million in 2002 compared to $461.9 million in 2001. The decrease in revenues was a result of the high energy commodity prices in 2001, slightly offset by increased revenue in the communications business group and power generation segment; increased production in coal, oil and gas and increased marketing volumes.

Consolidated operating expenses decreased from $306.9 million in 2001 to $295.9 million in 2002. The decrease was primarily due to a $13.9 million decrease in fuel costs and a $10.5 million decrease in administrative expenses offset by a $15.9 million increase in depreciation expense related to our increased investment in power generation. Administrative and general expenses decreased due to a decrease in commissions and incentive compensation partially offset by increased pension and administrative expenses.

Consolidated income taxes decreased $20.5 million as a result of the decrease in pre-tax earnings and a lower effective tax rate. Our effective tax rate decreased from 36.4 percent in 2001 to 31.9 percent in 2002 primarily due to a lower overall effective state income tax rate and the recognition of research and development credits in 2002.

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.

2001 Compared to 2000

Consolidated income from continuing operations for 2001 was $87.6 million, compared to $52.8 million in 2000, or $3.40 per share in 2001, compared to $2.37 per share in 2000. Income from discontinued operations was $0.5 million or $0.02 per share in 2001 compared to $36,000 in 2000. This equates to a 17.2 percent and 19.0 percent return on year-end common equity in 2001 and 2000, respectively. The return on year-end common equity in 2001 was diluted due to the net proceeds of $163 million from the public stock offering in 2001.

We reported record earnings in 2001, primarily due to strong natural gas marketing activity, increased fuel production, expanded power generation and increased wholesale off-system electric utility sales. Strong results in our integrated energy group and electric utility group were partially offset by losses in our communications group. Unusual energy market conditions related primarily to gas and electricity shortages in the West contributed to our strong financial performance in 2001 and 2000. There was an approximately $1.40 and $0.40 contribution to 2001 and 2000 earnings per share, respectively, due to high prevailing prices of gas and electricity and unusually wide gas trading margins in the last half of 2000 and first half of 2001.

Consolidated revenues were $461.9 million in 2001 compared to $292.1 million in 2000. Revenue increased in all segments. Daily volumes of natural gas marketed increased 22 percent from 860,800 million British thermal units per day in 2000 to 1,047,700 million British thermal units in 2001. Prices of financial and physical natural gas marketed decreased from an average of $2.77 per million British thermal units in 2000 to $2.14 per million British thermal units in 2001.

Earnings in 2001 included a $4.4 million after-tax charge ($0.17 per share) for a financial exposure to Enron Corporation and certain of its subsidiaries now in bankruptcy. The exposure is primarily related to the value of long-term swaps that hedged the price of natural gas to a power plant. We have taken action to mitigate this exposure. We are seeking authority to “net,” or offset, certain obligations with Enron and its subsidiaries, both payable and receivable, among our subsidiaries. If we are successful in these efforts, substantially all of the financial value of the fuel swap could be recovered, and we would not have any remaining exposure to Enron and its bankrupt subsidiaries.

Earnings in 2001 also reflect a $0.12 per share charge for employee stock bonus awards and the funding of a non-profit foundation to advance our charitable and philanthropic endeavors. Both of these transactions were funded with Black Hills Corporation common stock.

The following business group and segment information does not include discontinued operations and intercompany eliminations.

Integrated Energy Group

	2002	2001	2000
		(in thousands)	
Revenue:			
Power generation	$ 133,517	$ 80,233	$ 20,083
Energy marketing	37,704	83,884	40,204
Oil and gas	26,486	33,408	20,328
Coal mining	31,349	31,800	30,530
Total revenue	229,056	229,325	111,145
Operating expenses	140,065	126,429	49,957
Operating income	$ 88,991	$ 102,896	$ 61,188
Change in accounting principle	$ 896	--	--
Net income	$ 44,127	$ 57,930	$ 29,379

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

	2002	2001	2000
Fuel Production:			
Tons of coal sold	4,052,400	3,518,000	3,050,000
Barrels of oil sold	452,500	445,500	334,000
Mcf of natural gas sold	4,682,600	4,619,500	3,274,000
Mcf equivalent sales	7,397,800	7,292,500	5,278,000
Independent Power Capacity:			
MWs of independent power capacity in service	950(a)	617	250
MWs of independent power capacity under construction(b)	90	364	470

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

(b) Includes 90 MW plant under lease arrangement in the final stages of construction on December 31, 2002 and completed in the first quarter of 2003.

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

	2002	2001	2000
Energy Marketing Average Daily Volumes:			
Natural gas - MMBtus	1,088,200	1,047,700	860,800
Crude oil - barrels	57,200	36,500	44,300

<u>2002 Compared to 2001</u>

Net income of our integrated energy group decreased 24 percent in 2002 compared to 2001. Earnings 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 was impacted by a $4.4 million after-tax charge for an 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 integrated energy group's revenues declined slightly due to lower commodity prices and margins offset by increased power generation revenues due to an increase in capacity and acquisition of additional power generation partnership interests.

The integrated energy group's total operating expenses increased 11 percent due to 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.

<u>2001 Compared to 2000</u>

Net income of our integrated energy group nearly doubled in 2001 compared to 2000. These strong earnings resulted primarily from the unusually high prices of natural gas and high gas trading margins received in western markets during the first half of 2001, an increase in volumes marketed and fuel production, and expanded power generation.

In addition, in 2001, we reached a settlement of ongoing litigation with PacifiCorp concerning rights and obligations under a coal supply agreement under which PacifiCorp purchased coal from our coal mine to meet the coal requirements of the Wyodak power plant. As a result of this settlement, we recognized $5.6 million pre-tax non-operating income. In addition, we sold the "North Conveyor System" which resulted in a $2.6 million pre-tax gain. See Note 12 of Notes to Consolidated Financial Statements.

The integrated energy business group's revenues more than doubled to $229 million in 2001 compared to $111 million in 2000. The increase was driven by the full year effect of independent power operations revenues related to the July 2000 acquisition of Indeck Capital and an increase in revenue from fuel production and gas marketing. Daily volumes of natural gas marketed increased 22 percent.

The integrated energy business group's total operating expenses increased 153 percent due to expanded power production and increased volumes of fuel production and energy marketed. Operating income increased over 68 percent from 2000 levels due to higher production volumes.

Power Generation

Our power generation segment produced the following results:

	2002	2001	2000
		(in thousands)	
Revenue	$ 133,517	$ 80,233	$ 20,083
Operating income	55,363	27,455	20,374
Net income	18,033	1,576	3,242

2002 Compared to 2001

Earnings from the power generation segment increased $16.5 million primarily due to increased capacity that went into service during 2002 and the second half of 2001. During 2002 we had 726 net megawatts of independent power capacity in service, contributing to operations, compared to 617 net megawatts at December 31, 2001. Approximately 300 megawatts of the 617 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 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 an exposure to Enron Corporation.

Revenue increased 66 percent with a corresponding 48 percent increase to operating expenses. Approximately 43 percent of the revenue and 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 of an additional 30 percent interest was accounted for under the equity method of accounting. This acquisition gave us majority ownership and voting control of Harbor, therefore we now consolidate Harbor into our financial statements. As a result, 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 $1.9 million due to a $170 million increase in debt outstanding related to the expansion of our generation portfolio, partially offset by lower interest rates.

2001 Compared to 2000

2001 reflects the first full year of operations of our power generation segment and our continued expansion of generation facilities. At December 31, 2001 we owned 617 net megawatts in currently operating plants. Improved financial results due to increased production capacity was offset by a $4.4 million after-tax charge for Enron exposure, additional reserves for exposure to western power markets and reduced water flow at hydro power plants in New York.

Energy Marketing

Our energy marketing companies produced the following results:

	2002	2001	2000
		(in thousands)	
Revenue	$ 37,704	$ 83,884	$ 40,204
Operating income	18,065	53,662	24,113
Net income	12,739	34,566	13,973

2002 Compared to 2001

Earnings from the energy marketing segment 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.

Revenues decreased 55 percent from 2001 primarily due to lower gas margins. Unusual energy marketing conditions 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 do 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 gains (losses) were $(0.9) million in 2002 compared to $1.8 million in 2001, resulting in a year-over-year decrease of $(2.7) million pre-tax.

Operating expenses decreased 35 percent primarily due to 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.

2001 Compared to 2000

Earnings from the energy marketing segment increased $20.6 million primarily due to high gas margins received in the first half of 2001, as well as a 22 percent increase in natural gas average daily volumes marketed in 2001 compared to 2000. Revenues increased 109 percent from 2000 primarily due to higher daily volumes and high gas margins.

The unusual energy market conditions related primarily to natural gas and electricity shortages in California and our ability to capture the higher margins contributed significantly to the strong financial performance.

Oil and Gas

Oil and gas operating results were as follows:

	2002	2001	2000
		(in thousands)	
Revenue	$ 26,486	$ 33,408	$ 20,328
Operating income	6,471	15,193	7,906
Net income	4,783	10,197	4,992

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

	2002	2001	2000
Barrels of oil (in thousands)	4,880	4,055	4,413
Mmcf of natural gas	28,513	24,071	18,404
Total in Mmcf equivalents	57,793	48,401	44,882

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. As a result of the merger with Mallon Resources Corporation, which was completed in March 2003, we expect to more than double our net proved reserves and increase our production by nearly 50 percent. Mallon's proved reserves, as reported at December 31, 2001, were 53.3 billion cubic feet of gas equivalent.

2002 Compared to 2001

Net income 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.

2001 Compared to 2000

Record net income in 2001 was primarily a result of a 27 percent increase in the average price received and a 38 percent increase in production volumes. The increase in gas reserves at December 31, 2001 was due to strong drilling results and reserve acquisitions.

In 2001, we acquired operating and non-operating interests in 74 gas and oil wells located in Colorado and Wyoming from Stewart Petroleum Corporation of Denver, Colorado, for approximately $10 million. The acquired interests in these fuel assets represents approximately 10 billion cubic feet equivalent of natural gas. The acquisition increased our proved reserves by approximately 22 percent (based on year-end 2000 reserve estimates) and our production rates by 10 percent.

Coal Mining

Coal mining results were as follows:

	2002	2001	2000
		(in thousands)	
Revenue	$ 31,349	$ 31,800	$ 30,530
Operating income	9,092	6,586	8,795
Net income	8,572	11,591	7,172

2002 Compared to 2001

Coal mining earnings 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.

2001 Compared to 2000

Coal mining earnings increased $4.4 million as a result of a coal contract settlement, a gain on the sale of mining equipment and a 15 percent increase in tons sold, partially offset by lower average coal prices due to a coal contract settlement and an increase in mining related expenses. Tons of coal sold increased primarily due to the commencement of sales through our train load-out facility.

In 2001, we reached a settlement of ongoing litigation with PacifiCorp concerning rights and obligations under a coal supply agreement under which PacifiCorp purchased coal from our coal mine to meet the coal requirements of the Wyodak power plant. As a result of this settlement, we recognized $5.6 million pre-tax non-operating income. In addition, we sold the "North Conveyor System" which resulted in a $2.6 million pre-tax gain. See Note 12 of Notes to Consolidated Financial Statements.

Electric Utility Group

	2002	2001	2000
		(in thousands)	
Revenue	$ 162,186	$ 212,355	$ 173,308
Operating expenses	104,026	128,247	105,100
Operating income	$ 58,160	$ 84,108	$ 68,208
Net income	$ 30,217	$ 45,238	$ 37,178

We currently have a winter peak of 344 megawatts established in December 1998 and a summer peak of 392 megawatts established in August 2001. We own 435 megawatts of electric utility generating capacity and purchase an additional 60 megawatts under a long-term agreement (decreasing to 55 megawatts in 2003).

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.

2001 Compared to 2000

Electric revenue increased 23 percent in 2001 compared to 2000. The increase in electric revenue in 2001 was primarily due to a 78 percent increase in wholesale off-system sales at an average price that was 27 percent higher than the average price in 2000. The increase in off-system sales was driven by high spot market prices for energy in early 2001, which enabled us to generate more energy from our combustion turbine facilities, including the Neil Simpson combustion turbine, which we placed into commercial operation in June 2000. Megawatt-hours generated from our oil-fired diesel and natural gas-fired combustion turbines were 440,368 in 2001, compared to 305,767 in 2000. Historically, market prices were not sufficient to support the economics of generating from these facilities, except to meet peak demand and as standby use for native load requirements.

Firm kilowatt-hour sales increased 2 percent in 2001. Residential and commercial sales increases of 3 percent in 2001 were partially offset by a slight decrease in industrial sales, primarily due to load reductions at Homestake Gold Mine. Degree days, a measure of weather trends, were 3 percent below normal in 2001 and 4 percent below 2000.

Revenue per kilowatt-hour sold was 7.0 cents in 2001 compared to 6.4 cents in 2000. The number of customers in the service area increased to 59,237 from 58,601 in 2000. The increase in the revenue per kilowatt-hour sold in 2001 is due to a 41 percent increase in wholesale off-system sales to 965,030 megawatt-hours and strong average wholesale power prices.

Electric utility operating expenses increased 22 percent in 2001 primarily due to a 29 percent increase in purchased power costs and a 14 percent increase in the average cost of generation. The increase in the average cost of generation was primarily associated with the operation of certain gas-fired combustion turbines.

In addition, 2001 results include a $2.0 million after-tax non-cash charge related to the contribution of Black Hills Corporation Common Stock to the newly formed Black Hills Corporation Foundation. This Foundation was created to enhance our longstanding practice of giving back to our communities. Through the Foundation, we may strengthen our service to our valued customers and fellow citizens for generations to come.

Communications Group

	2002	2001	2000
		(in thousands)	
Revenue	$ 32,677	$ 20,258	$ 7,689
Operating expenses	40,124	33,508	20,175
Operating loss	$ (7,447)	$ (13,250)	$ (12,486)
Net loss	$ (7,260)	$ (12,300)	$ (11,382)

	2002	2001	2000
Residential customers	21,700	15,660	8,368
Business customers	3,061	2,250	646
Fiber optic backbone miles	242	242	210
Hybrid fiber coaxial cable miles	818	737	588

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, 2002, we had invested approximately $150 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, which completes our initial infrastructure build-out. We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers. We expect a continuation of better financial performance in 2003 as we continue to increase the customer base. We expect our communications group will sustain approximately $3.5 — $4.0 million in net losses in 2003, and profitability is expected in 2004. The recovery of capital investment and future profitability are dependent on our ability to maintain our customer base and is subject to the risk that technological advances may render our network obsolete.

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.

2001 Compared to 2000

Our customer base nearly doubled in 2001 to 15,660 residential customers and 2,250 business customers. The increase in revenues from a larger customer base in 2001 was partially offset by increases in reserves for inventory and carrier billings and increased interest expense. Operating expense increased due to the expansion of the business.

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 the carrying values of our long-lived assets, including goodwill and other intangibles, for impairment 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 a discrete time period 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 internal budgets. Although we believe our estimates of future cash flows are reasonable, different assumptions regarding such cash flows could materially affect our evaluations.

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 three 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 $121.3 million at December 31, 2002. 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.

During 2002, due to the current depressed market value of merchant generation plants, we evaluated the carrying value of our 40 megawatt gas-fired Pepperell plant which is part of our non-regulated power generation segment. We determined, based on our assumptions, 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 $7.2 million at December 31, 2002. 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 (loss) from discontinued operations, net of taxes" on the Consolidated Statements of Income. This impairment charge was offset by income of $0.9 million, after-tax, from the write-off of negative goodwill at our non-regulated power generation segment, as required by SFAS 142. This amount is reported as "Change in accounting principle, net of taxes" on the Consolidated Statements of Income. We completed our 2002 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, 2002, we can make no assurances 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 based on a number of assumptions about variables. We can make no assurances 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.

<u>Non-trading (Hedging)</u>

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.

<u>Energy Trading and Marketing</u>

We have historically accounted for the activities at our natural gas marketing and crude oil marketing subsidiaries as energy trading activities as defined by Emerging Issues Task Force Issue No. 98-10, "Accounting for Contracts Involving Energy Trading and Risk Management Activities" (EITF 98-10). As such, all of the contracts at our energy marketing businesses, whether or not derivatives under SFAS 133, have historically been 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 energy 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 energy marketing businesses, net in Operating revenues on the Consolidated Statements of Income.

<u>Valuation</u>

Fair values of derivative instruments and energy trading contracts originated on or before October 25, 2002, 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.

<u>New Accounting Policy</u>

During 2002, the EITF discussed 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) and reached a consensus on certain issues. EITF 98-10 requires that energy trading contracts be accounted for at fair value. EITF 02-3 rescinds EITF 98-10 and is effective for any new contracts entered into after October 25, 2002. For energy trading contracts entered into through October 25, 2002, such contracts have 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 derivative, as defined by SFAS 133, are required to be accounted for at historical cost and we will report this as a cumulative effect of an accounting change. Our energy contracts that qualify as derivatives will continue to be accounted for at fair value under SFAS 133.

EITF 02-3 requires that energy trading contracts and derivatives, whether settled financially or physically, be reported in the income statement on a net basis effective January 1, 2003.

Through December 31, 2002, we have presented the unrealized and realized gains and losses, whether or not settled financially or physically, from the activities of our energy marketing businesses, net in Operating revenues on the Consolidated Statements of Income. As discussed below, this current presentation will be effected by the adoption of EITF 02-3.

For our crude oil marketing operations, substantially all crude oil contracts previously 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 will no longer be recorded at fair value since they do not meet the definition of derivatives, as defined by SFAS 133, and will be accounted for under the accrual method of accounting. In addition, this will affect the presentation of the related revenues and energy purchase expenses, as under current accounting principles generally accepted in the United States of America, the results of these contracts will need to be presented on a gross basis.

In addition to all of the contracts at our crude oil marketing operations no longer being recorded at fair value, certain contracts and physical positions at our natural gas marketing operations will no longer be recorded at fair value since they do not meet the definition of a derivative under SFAS 133. Since we use transportation contracts and physical positions to economically hedge our natural gas portfolio, to the extent these items can no longer be accounted for at fair value, it will introduce volatility into future earnings of our natural gas marketing operations.

On January 1, 2003 this adjustment will be recorded as a cumulative effect of an accounting change totaling $(3.2) million, net of tax.

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 guarantee that we will continue to experience the same credit loss rates that we have in the past.

Stock-based Employee Compensation Plans

At December 31, 2002, we had several stock-based employee compensation plans, which are described more fully in Note 6 of our Notes to Consolidated Financial Statements. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, “Accounting for Stock Issued to Employees,” and related interpretations. Stock-based employee compensation cost is not reflected in net income, as all options granted under those 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 we had applied the fair value recognition provisions of SFAS 123, “Accounting for Stock-Based Compensation,” (SFAS 123) to stock-based employee compensation.

	Year Ended December 31		
	2002	2001	2000
	(in thousands, except per share amounts)		
Net income available for common stock, as reported	$ 61,229	$ 87,550	$ 52,770
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(990)	(705)	(338)
Pro forma net income	$ 60,239	$ 86,845	$ 52,432
Earnings per share:			
As reported -			
Basic			
Continuing operations	$ 2.35	$ 3.43	$ 2.39
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.28	$ 3.45	$ 2.39
Diluted			
Continuing operations	$ 2.33	$ 3.40	$ 2.37
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.26	$ 3.42	$ 2.37
Pro forma -			
Basic			
Continuing operations	$ 2.32	$ 3.40	$ 2.37
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.25	$ 3.42	$ 2.37
Diluted			
Continuing operations	$ 2.30	$ 3.37	$ 2.36
Discontinued operations	(0.10)	0.02	--

Change in accounting principle	0.03	--	--
Total	$ 2.23	$ 3.39	$ 2.36

Pension and Other Postretirement Benefits

The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the use of assumptions used by actuaries in calculating the amounts. Those assumptions, as further described in Note 13 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, 2002, 2001 and 2000, we recorded non-cash (expense) income related to our pension plans of approximately $(0.2) million, $2.1 million, and $1.8 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. The market value of the plan's assets has been affected by sharp declines in equity markets since the end of 2000. Plan assets (lost) earned $(6.5) million, $(13.1) million and $7.5 million during 2002, 2001 and 2000, respectively. In the recently completed actuarial valuation, we decreased the assumed rate of return on plan assets from 10.5 percent to 10 percent. This change is expected to increase pension costs in 2003 and beyond by approximately $0.2 million per year.

The 10 percent assumed rate of return 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 (source: Bloomberg), 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 .18 percent for US index equity and .45 percent for international equity. The long-term estimated fixed income return was estimated based on the historical annual returns on intermediate-term treasury bonds returns of 6.26 percent from 1950 to 2002. Cash returns are estimated to be 200 basis points below intermediate-term treasury bonds.

As a result of the decline in the value of our plan assets and due to a reduction in the discount rate used to determine the year end liability, during the fiscal year ended at December 31, 2002, we were required to recognize an additional minimum liability as prescribed by SFAS 87. The liability was recorded as a reduction to common equity through a $8.1 million after-tax charge to Accumulated other comprehensive income on the Consolidated Balance Sheets, but the adjustment did not affect net income for 2002. The charge to Accumulated other comprehensive income will be restored through common equity in future periods to the extent fair value of the plan assets exceed the accumulated benefit obligation.

Based on our recently completed plan forecasts, we estimate that we will be required to make cash contributions to the pension plan beginning in 2004 in the amount of approximately $2.6 million in 2004, $7.0 million in 2005, $7.2 million in 2006, $7.0 million in 2007, $3.4 million in 2008 and approximately $0.7 million per year thereafter.

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 $0.8 million in 2002 and $0.5 million in 2001 and 2000. The plans are unfunded. The provisions of SFAS 87 required us to record an additional minimum liability of $1.1 million at December 31, 2002. The liability was recorded as a reduction to common equity through a $0.7 million after-tax charge to Accumulated other comprehensive income on the Consolidated Balance Sheets.

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, 2002, 2001 and 2000, we recorded other postretirement benefit expense of approximately $1.0 million each year 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, 2002 Accumulated Postretirement Benefit Obligation	Impact on 2002 Service and Interest Cost
	(in thousands)	
Increase 1%	$ 1,574	$166
Decrease 1%	$(1,274)	$(134)

In selecting an assumed discount rate, we considered comparable high-grade bond rates at which the retirement rates could be effectively settled. Based on these considerations, we have changed the discount rate used by the plan actuary to determine our other postretirement benefit expense, for years 2003 and beyond to 6.75 percent from 7.5 percent in 2002. 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 2003 and beyond, from 8 percent decreasing gradually to 6 percent, to 12 percent in 2002 decreasing gradually to 5 percent in 2009. These changes will increase the future other postretirement benefit expense included on our income statement by approximately $0.2.

Liquidity and Capital Resources

Cash Flow Activities

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 continue to fund property and investment additions primarily related to construction and acquisition of additional electric generation facilities for our integrated 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 $40.4 million, due to a $50.0 million increase in deferred income taxes and a $15.9 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 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 $305.2 million, which includes $233.1 million for property, plant and equipment additions and $70.8 million related to acquisitions. Net cash inflows from financing activities totaled $136.2 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 $50.0 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 expires on May 26, 2003. This financing is 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 and will be used to fund our utility’s portion of the construction and installation costs for an AC-DC-AC Converter Station; 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 that expires 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.

2001

In 2001, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay long-term debt maturities and to fund a material amount of our property additions. We funded property and investment additions primarily related to construction of additional electric generation facilities for our integrated energy business group through a combination of operating cash flow, increased short-term debt and long-term non-recourse project financing. Cash flows from operations increased $110.8 million, primarily due to increased net income, depreciation, deferred taxes and decreased working capital.

In the second quarter of 2001, we issued 3.4 million shares of common stock through an underwritten public offering at $52 per share. Total net proceeds of approximately $163 million were used to repay a portion of current indebtedness under revolving credit facilities, to fund various power plant construction projects and for general corporate purposes.

Also, in the second quarter of 2001 we acquired the Fountain Valley facility, a 240 megawatt generation facility located near Colorado Springs, Colorado, featuring six LM-6000 simple-cycle, gas-fired turbines from Enron Corporation. The facility became operational in the third quarter of 2001. Total project cost was approximately $183 million that we financed primarily with non-recourse debt. We have an 11-year contract with Public Service Company of Colorado to utilize the facility for peaking purposes under a tolling arrangement in which we assume no fuel risk.

In the third quarter of 2001, we purchased a 277 megawatt gas-fired co-generation power plant project located in North Las Vegas, Nevada from Enron North America, a wholly owned subsidiary of Enron Corporation. At acquisition, the facility had a 53 megawatt co-generation power plant in operation of which we own 50 percent. Although we only own 50 percent of this power plant, under generally accepted accounting principles we are required to consolidate 100 percent of this plant. Most of the power from the 53 megawatt facility is sold under a long-term contract expiring in 2024. In addition, the project also had a 224 megawatt combined-cycle expansion under construction, of which we own 100 percent. The facility became fully operational in January 2003 and utilizes LM-6000 technology. The power to be generated by the expansion project is also under a long-term sales contract that expires in 2017. Total cost of the project is estimated to be approximately $325 million of which $240 million was expended and financed with short-term borrowings at December 31, 2001.

In addition, during the third quarter of 2001, we completed a $400 million revolving credit facility, which replaced our previous short-term credit lines, which totaled $290 million.

Dividends

Dividends paid on our common stock totaled $1.16 per share in 2002. This reflected increases approved by our board of directors from $1.12 per share in 2001 and $1.08 per share in 2000. All dividends were paid out of current earnings. Our three-year annual dividend growth was 3.7 percent. In January 2003, our board of directors increased the quarterly dividend 3.4 percent to 30 cents per share. If this dividend is maintained during 2003, it will be equivalent to $1.20 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 are our revolving bank facilities and cash provided by operations. As of December 31, 2002 we had approximately $80 million of cash unrestricted for operations and $395 million of credit through revolving bank facilities. Approximately $50 million of the cash balance at December 31, 2002 was restricted by subsidiary debt agreements that limit our subsidiaries' ability to dividend cash to the parent company. The bank facilities consisted of a $195 million facility due August 26, 2003 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, 2002, we had $290.5 million of bank borrowings outstanding under these facilities. After inclusion of applicable letters of credit, the remaining borrowing capacity under the bank facilities was $64.2 million at December 31, 2002.

The above bank facilities include covenants that are common in such arrangements. Several of the facilities require that we maintain a consolidated net worth in an amount of not less than the sum of $425 million and 50 percent of our aggregate consolidated net income beginning April 1, 2002; 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. In addition, the $195 million 364-day credit facility and the $200 million three-year credit facility contain a liquidity covenant that requires us to have $30 million of liquid assets as of the last day of each fiscal quarter beginning with December 31, 2002. Liquid assets are defined as unrestricted cash and available unused capacity under our credit facilities. 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, 2002 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, 2002, we were in compliance with the above covenants.

Some of our facilities previously had a covenant whereby we were required to maintain a credit rating of at least "BBB-" from Standard & Poor's or "Baa3" from Moody's Investor Service. The facilities that contained the rating triggers were amended during the second quarter of 2002 to remove default provisions pertaining to our credit rating status.

Our consolidated net worth was $535.2 million at December 31, 2002, which was approximately $87 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, 2002 was 53.6 percent, our total debt recourse leverage ratio was 61.3 percent and our total debt recourse and non-recourse leverage ratio was 64.7 percent.

At December 31, 2002, we also had a $50 million short-term secured financing in place that matures on May 26, 2003.

In addition, Enserco Energy, Inc., our natural gas marketing unit, has a $135 million uncommitted, discretionary line of credit to provide support for the purchase of natural gas. We provided no guarantee to the lender under this facility. At December 31, 2002, there were outstanding letters of credit issued under the facility of $46.7 million with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc., our crude oil marketing unit, had a $25.0 million uncommitted, discretionary credit facility. This line of credit provided credit support for the purchases of crude oil by Black Hills Energy Resources. We provided no guarantee to the lender under this facility. At December 31, 2002, Black Hills Energy Resources had letters of credit outstanding of $13.5 million and no borrowing balance outstanding on its overdraft line.

We continue to seek non-recourse project-level financing for our independent power projects. Due to creditworthiness concerns with counterparties, financing arrangements for the Las Vegas II power plant have been delayed.

Allegheny Energy Supply Company (AESC), a subsidiary of Allegheny Energy Inc., has a contract to purchase all of the capacity and all associated energy and ancillary services from our 224 megawatt Las Vegas II plant. Both AESC and its parent, Allegheny Energy Inc. have recently had their credit ratings downgraded below investment grade status and have technically defaulted on some of their credit agreements with other counterparties. Las Vegas II became operational in January 2003 and has been funded with the corporate credit facilities. Total construction and acquisition costs, including Las Vegas I, are expected to be $325 million of which $314 million was expended as of December 31, 2002. In March 2003 we received a $15 million bank letter of credit from AESC which expires in December 2003. In the event the bank letter of credit is not renewed at that time, the full amount of the letter of credit can be drawn. The bank letter of credit was provided in conjunction with a tolling contract for capacity and energy from the power plant expansion.

On November 27, 2002 we filed a Form S-3 Registration Statement with the Securities and Exchange Commission. This "shelf registration" became effective on February 5, 2003 and will enable us to proceed with equity or debt offerings in a total amount of up to $400 million in capital as opportunities and capital market conditions warrant.

If we are not successful in extending or replacing the $245 million of facilities that expire in 2003 or in obtaining other financing, a deficiency in our liquidity could occur. Our ability to obtain additional financing will depend upon a number of factors, including our future performance and financial results and capital market conditions. We can provide no assurance that we will be able to raise additional capital on reasonable terms or at all.

The following information is provided to summarize cash obligations and commercial commitments. As shown in the table, we have $23.4 million of long-term debt maturing in 2003.

	Payments Due by Period (in thousands)				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Notes payable	$ 340,500	$340,500	$ --	$ --	$ --
Long-term debt	642,310	23,448	88,324	266,921	263,617
Operating lease obligations (a)	131,230	2,322	6,966	6,966	114,976
Unconditional purchase obligations (b)	183,833	14,027	26,233	25,974	117,599
Other long-term obligations (c)	49,213	--	9,600	14,200	25,413
Total contractual cash obligations	$ 1,347,086	$380,297	$131,123	$314,061	$521,605

(a) Represents the Off Balance Sheet Arrangement described below.

(b) Unconditional purchase obligations include the capacity costs associated with a purchase power agreement with PacifiCorp and certain 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, 2002.

(c) Includes the forecasted minimum contributions for our pension plan for the next ten years based upon an actuary study using a 10.0 percent asset return assumption and a 6.75 percent discount rate and our reclamation liability for our coal mine. Under our coal mining permit, we are required to reclaim all land where we have mined coal reserves. The cost of reclaiming the land is accrued as the coal is mined. While the reclamation process takes place on a continual basis, much of the reclamation occurs over an extended period after we mine the area. As of December 31, 2002, accrued reclamation costs were approximately $18.5 million.

Off Balance Sheet Arrangements

Black Hills Generation, a subsidiary in our power generation segment, has entered into agreements with Wygen Funding, Limited Partnership, an unrelated, unconsolidated special purpose entity (SPE), to lease the Wygen plant, a 90 megawatt coal-fired power plant under construction in Campbell County, Wyoming. Wygen Funding owns the Wygen plant, has financed the project and will lease it to our subsidiary upon completion of construction. Lease payments are expected to commence in the second quarter of 2003. We entered into this financing arrangement due to its low cost of financing. The SPE has an aggregate financing commitment from equity and debt participants of $140 million. The Wygen plant is the only asset that the SPE owns. The initial lease term 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 project. At the end of each lease term, we may renew the lease, purchase the facility, or sell the facility on behalf of the SPE, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the investors, we will be required to make a payment to the SPE of the shortfall up to 83.5 percent of the adjusted acquisition cost. We have guaranteed the obligations of Black Hills Generation to the SPE.

As of December 31, 2002, costs incurred totaled $107.1 million, and the total costs for the completed facility are expected to be $130 — $140 million. The lease is currently considered an operating lease for financial accounting purposes. Therefore, neither the facility nor the related obligations are reported on our balance sheet. The lease is a London Interbank Offered Rate (LIBOR) based variable rate obligation. Consequently, as market rates increase, the payments under this lease will also increase. Annual payments of approximately $3.5 million represent future minimum payments under the first five-year lease term calculated using an effective borrowing rate of 2.5 percent (the rate in effect at December 31, 2002). A one percent increase in the borrowing rate will increase the annual lease payment by approximately $1.4 million.

In January 2003 the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, “Consolidation of Variable Interest Entities”. Under the new accounting interpretation, we will be required to consolidate the SPE by July 1, 2003, unless the transaction is restructured. We currently do not plan on restructuring the lease. The effect of consolidating the SPE into our financials would be to record both the Wygen asset and its related debt on our balance sheet which will be in the range of $130 — $140 million. In addition, the net effect of consolidating the income statement of the SPE would be to recognize the depreciation and interest expense of the SPE in place of recognizing lease expense. This charge is estimated to have approximately a $3.5 million per year negative effect on pre-tax income using a 40 year depreciable life.

Guarantees

We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2002, we had guarantees totaling $350 million in place of which $135 million expired in January 2003. Of the $350 million, $217 million was related to guarantees associated with subsidiaries’ debt to third parties, which is recorded as liabilities on the Consolidated Balance Sheets, $89 million was to guarantee a subsidiary’s obligation on an off balance sheet transaction, $13 million was related to performance obligations under subsidiary contracts and $31 million was related to indemnification for reclamation and surety bonds of subsidiaries. For more information on these guarantees, see Note 3 of our Notes to Consolidated Financial Statements.

The following table summarizes our guarantees outstanding at December 31, 2002:

Nature of Guarantee	Outstanding at December 31, 2002	Year Expiring
	(in thousands)	
Completion guarantee for the expanded facilities under a construction loan for Black Hills Colorado	$135,000	2003
Guarantee of secured financing for the Las Vegas II project	50,000	2003
Guarantee payments under certain energy marketing derivative, power and gas agreements	7,500	2003
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee performance of Black Hills Generation under a power sales agreement	5,000	2004
Guarantee obligations under the Wygen Plant Lease	89,400	2008
Guarantee payment and performance under credit agreements for two combustion turbines	32,000	2010
Indemnification for subsidiary reclamation/surety bonds	30,720	2003
	$350,370	--

Credit Ratings

As of February 28, 2003, 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 “Baa2” and “BBB+” by Moody’s and Standard & Poor’s, respectively. Moody’s downgraded our issuer credit rating to “Baa3” in December 2002. These security ratings are subject to revision and/or withdrawal at any time by the respective rating organizations. Any further reduction in our ratings by Moody’s and Standard & Poor’s, particularly a reduction to a level below investment-grade, could adversely affect our ability to refinance our existing debt and to complete new financings.

Capital Requirements

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

	2002	2001	2000
		(in thousands)	
Property additions and acquisition costs:			
Integrated energy	$ 249,683	$ 532,774	$ 130,332
Electric utility	31,251	41,313	25,257
Communications and other	22,984	20,055	59,377
Common stock dividends	31,116	28,517	23,527
Maturities/redemptions of long-term debt	32,527	13,960	1,330

	$ 367,561	$ 636,619	$ 239,823

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.
- 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, which 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 we 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 projected plant construction, other integrated energy investments, regulated utility capital improvements and completion of the communications network are as follows:

	2003	2004	2005
		(in thousands)	
Integrated energy	$ 211,485	$ 280,875	$ 285,572
Electric utility	49,632	25,577	18,422
Communications	8,706	5,422	5,030
	$ 269,823	$ 311,874	$ 309,024

Our integrated energy business group’s forecasted capital requirements include deployment of $625 million for generating projects and acquisitions of proven producing natural gas properties and low-risk exploration and development drilling in years 2003-2005.

We expect to finance our integrated energy business group’s purchase and construction of 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.

In addition to the above forecasted capital items, we will lease the Wygen plant, a 90 megawatt coal-fired plant under construction at our Wyodak, Wyoming site through a synthetic lease financing arrangement discussed above under Short-term Liquidity. Because of the leasing arrangement, the $130 — $140 million total construction cost of the plant is not included in the above three-year capital expenditure forecast. Wygen is similar in design to our Neil Simpson II facility, which was completed in 1995 at the same site. The plant will run on low-sulfur coal fed by conveyor from our adjacent Wyodak coal mine and will use the latest available environmental control technology. The Wygen plant became operational in February 2003.

Forecasted capital expenditures for our electric utility operations include completion of construction of an AC/DC/AC Tie which is expected to be placed in service in 2003, transmission and substation projects, re-build projects on existing transmission lines, distribution projects in response to customer requests for electric service, capital projects associated with our utility’s existing generation plants, and other miscellaneous items.

Our communications group’s capital requirements forecast consists of nominal extensions of the base network to reach additional customers and capital improvements to the existing network infrastructure.

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 8 and 9 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 its 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

Natural Gas Marketing

We have a natural gas marketing business specializing in producer services, end-use origination and wholesale marketing that conducts business in 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 asset optimization services to 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 market third party natural gas. These functions are predominately value-added services and/or 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 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 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 using 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.

At year-end 2002, the three-day natural gas trading portfolio VaR calculation was $(2.1) million using a 99 percent confidence level.

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.

Our natural gas marketing operations fall under the purview of EITF 98-10, SFAS 133, and for contracts entered into after October 25, 2002, in accordance with EITF 02-3. 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:

	2002		2001	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of MMBtu's)				
Natural gas basis swaps purchased	72,340	1	9,882	1
Natural gas basis swaps sold	72,329	1	10,696	1
Natural gas fixed-for-float swaps purchased	10,675	1	10,646	2
Natural gas fixed-for-float swaps sold	17,934	1	11,815	2
Natural gas swing swaps purchased	--	--	465	1
Natural gas swing swaps sold	--	--	930	1
Natural gas physical purchases	42,813	1.25	13,159	1
Natural gas physical sales	41,654	1	19,339	1

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2002 and 2001, 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, 2002 and 2001 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain
December 31, 2002	$ 29,559	$ 2,406	$ 28,535	$ 409	$ 3,021
December 31, 2001	$ 29,755	$ 661	$ 25,437	$ 953	$ 4,026

The following table provides a reconciliation of the activity in energy trading contracts marked to market during the year ended December 31, 2002 (in thousands):

Total fair value of natural gas marketing contract net assets at December 31, 2001	$ 4,026
Net cash settled during the year on contracts that existed at December 31, 2001	(1,863)
Change in fair value due to change in techniques and assumptions	--
Unrealized gain/(loss) on new contracts entered during the year and still existing at December 31, 2002	(2,918)
Realized gain/(loss) on contracts that existed at December 31, 2001 and were settled during year	(2,477)
Unrealized gain/(loss) on contracts that existed at December 31, 2001 and still exist at December 31, 2002	6,253
Total fair value of natural gas marketing contract net assets at December 31, 2002	$ 3,021

At December 31, 2002, we had a mark to fair value unrealized gain of $3.0 million for our natural gas marketing activities. Of this amount, $1.0 million was current and $2.0 million was non-current. The source of fair value measurements were as follows (in thousands):

	Maturities		
Source of Fair Value	2003	2004	Total Fair Value
Actively quoted (i.e., exchange-traded) prices	$ (4,190)	$ --	$ (4,190)
Prices provided by other external sources	5,214	1,997	7,211
Modeled	--	--	--
Total	$ 1,024	$ 1,997	$ 3,021

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.

Our crude oil marketing operations have historically fallen under the purview of EITF 98-10 and as such, all crude oil contracts entered into on or before October 25, 2002, have 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 our crude oil marketing operations do not meet the definition of derivatives under SFAS 133 and hence none of these contracts entered into after October 25, 2002 will be marked-to-market in future financial statements.

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

	2002		2001	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of barrels)				
Crude oil purchased	4,081	0.5	3,139	1
Crude oil sold	4,150	0.5	3,142	1

On December 31, 2002 and 2001, our crude oil contracts entered into on or before October 25, 2002 were marked to fair value 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, 2002 and 2001 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
December 31, 2001	$ 6,267	$ --	$ 5,496	$ --	$ 771

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 and are routinely reviewed by our Audit Committee.

Any hedging strategies are conducted within an enterprise wide perspective. As more fully defined in the next section, we have some fuel procurement risk within our 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, 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.

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

At December 31, 2002, we had a portfolio of swaps to hedge portions of our 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, 2002, 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 accumulated other comprehensive income and the ineffective portion was reported in earnings.

On December 31, 2002 and 2001, 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, 2002								
Crude oil swap	360,000	1	$ --	$--	$ 976	$ --	$ (914)	$ (62)
Natural gas swaps	1,650,000	1	58	--	744	--	(686)	--
	--	--	$ 58	$--	$ 1,720	$ --	$ (1,600)	$ (62)
December 31, 2001								
Crude oil swaps	90,000	1	$ 529	$ --	$ --	$ --	$ 529	$ --
Natural gas swaps	1,216,000	1	1,593	--	--	--	1,463	130
	--	--	$2,122	$ --	$ --	$ --	$ 1,992	$ 130

*Crude in bbls, gas in MMBtu's

Most of our crude oil and natural gas hedges are highly effective, resulting in very little earnings impact prior to realization. During 2002, we recorded a $0.1 million loss due to ineffectiveness for certain crude oil swaps due to basis risk.

All existing hedges at December 31, 2002 expire during the year ended December 31, 2003. The unrealized earnings gains or losses currently recorded in accumulated other comprehensive income are expected to be realized in earnings during 2003. Based on December 31, 2002 market prices, $1.6 million loss will be realized and reported in earnings during 2003. These estimated realized losses for 2003 were calculated using December 31, 2002 market prices. Estimated and actual realized losses will likely change during 2003 as market prices change.

Power Generation

We have a portfolio of gas-fired fueled generation assets located throughout several western states. 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, will 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, 2002, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2002, we had $237.3 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of four years and a fair value of $(18.3) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2002 and 2001, 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, 2002								
Swaps on project financing	$212,256	5.98%	4	$ --	$ --	$ 9,345	$ 7,844	$ (17,189)
Swaps on corporate debt	25,000	5.28%	1	--	--	947	166	(1,113)
	$237,256	--	-	$ --	$ --	$10,292	$ 8,010	$ (18,302)
December 31, 2001								
Swaps on project financing	$316,397	5.85%	4	$ --	$ 5,746	$10,212	$ 5,949	$ (10,415)
Swaps on corporate debt	75,000	4.45%	3	--	--	1,535	217	(1,752)
	$391,397	--	-	$ --	$ 5,746	$11,747	$ 6,166	$ (12,167)

We anticipate a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2003. Based on December 31, 2002 market interest rates, $10.3 million will be realized as additional interest expense during 2003. Estimated and realized amounts will likely change during 2003 as market interest rates change.

At December 31, 2002, we had $770.0 million of outstanding, variable-rate debt of which $532.8 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 $5.3 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).

	2003	2004	2005	2006	2007	Thereafter	Total
Cash equivalents							
Fixed rate	$79,811	$ --	$ --	$ --	$ --	$ --	$ 79,811
Long-term debt							
Fixed rate	$ 3,122	$ 2,017	$ 2,026	$ 2,037	$ 2,049	$ 201,515	$212,766
Average interest rate	9.31%	9.50%	9.52%	9.54%	9.57%	7.88%	7.96%
Variable rate (a)	$20,326	$ 58,932	$ 25,350	$ 137,783	$ 125,052	$ 62,101	$429,544
Average interest rate	3.22%	2.87%	3.22%	3.28%	3.19%	3.24%	3.19%
Total long-term debt	$23,448	$ 60,949	$ 27,376	$ 139,820	$ 127,101	$ 263,616	$642,310
Average interest rate	4.03%	3.09%	3.69%	3.38%	3.29%	6.78%	4.77%

(a) Approximately 49 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 5.98 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 guaranties, 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 68 percent of our credit exposure was with investment grade companies. For the 32 percent credit exposure with non-investment grade rated counterparties, approximately 62 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 five 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 107 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 46 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 — $1.0 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 2002 or pending adoption.

Safe Harbor for Forward Looking Information

This 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 effects on our business resulting from the financial difficulties of other energy companies, including the effects on liquidity in the energy marketing and power generation businesses and markets and perceptions of the energy and energy marketing business;
- the effects on our business resulting from a lowering of our credit rating (or actions we may take in response to changing credit ratings criteria), including demands for increased collateral by our current or new counterparties, refusal by our current or potential counterparties or customers to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms favorable to us;
- capital market conditions;
- unanticipated developments in the western power markets, including unanticipated governmental intervention, deterioration in the financial condition of counterparties, defaults on amounts due from counterparties, adverse changes in current or future litigation, market disruption and adverse changes in energy and commodity supply, volume and pricing and interest rates;
- pricing and transportation of commodities;
- population changes and demographic patterns;
- prevailing governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and other capital investments, and present or prospective wholesale and retail competition;
- the continuing efforts by or on behalf of the State of California to restructure its long-term power purchase contracts and efforts by regulators and private parties in several western states to recover refunds for alleged price manipulation;
- changes in and compliance with environmental and safety laws and policies;
- weather conditions;
- competition for retail and wholesale customers;
- market demand, including structural market changes;
- changes in tax rates or policies or in rates of inflation;
- changes in project costs;
- unanticipated changes in operating expenses or capital expenditures;
- technological advances by competitors;
- competition for new energy development opportunities;
- the cost and other effects of legal and administrative proceedings that influence our business;
- the effects on our business, including the availability of insurance, resulting from terrorist actions or responses to such actions; 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 and subsidiaries as of December 31, 2002 and 2001, 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, 2002. Our audits also included the financial statement schedule listed in the Table of Contents at Item 15. These financial statements and financial statement schedule are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

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 and as discussed in Note 1 to the consolidated financial statements, effective January 1, 2001, the Corporation adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
March 10, 2003

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2002	2001	2000
	(in thousands, except per share amounts)		
Operating revenues	$ 423,919	$ 461,938	$ 292,142
Operating expenses:			
Fuel and purchased power	65,432	79,356	57,583
Operations and maintenance	73,091	72,445	48,773
Administrative and general	67,864	78,339	43,318
Depreciation, depletion and amortization	69,738	53,811	32,624
Taxes, other than income taxes	19,781	22,993	14,904
	295,906	306,944	197,202
Equity in earnings of unconsolidated subsidiaries	4,588	14,776	20,149
Operating income	132,601	169,770	115,089
Other income (expense):			
Interest expense	(41,234)	(39,479)	(30,136)
Interest income	629	2,372	7,067
Other expense	(554)	(4,759)	(2,278)
Other income	4,575	14,016	4,685
	(36,584)	(27,850)	(20,662)
Income from continuing operations before minority interest, income taxes and change in accounting principle	96,017	141,920	94,427
Minority interest	(3,162)	(4,186)	(11,273)
Income taxes	(29,662)	(50,150)	(30,342)
Income from continuing operations before change in accounting principle	63,193	87,584	52,812
Income (loss) from discontinued operations, net of taxes	(2,637)	493	36
Change in accounting principle, net of taxes	896	--	--

Net income	61,452	88,077	52,848
Preferred stock dividends	(223)	(527)	(78)
Net income available for common stock	$ 61,229	$ 87,550	$ 52,770
Earnings per share of common stock:			
Basic-			
Continuing operations	$ 2.35	$ 3.43	$ 2.39
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.28	$ 3.45	$ 2.39
Diluted-			
Continuing operations	$ 2.33	$ 3.40	$ 2.37
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.26	$ 3.42	$ 2.37
Weighted average common shares outstanding:			
Basic	26,803	25,374	22,118
Diluted	27,167	25,771	22,281

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	2002	2001
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 79,811	$ 29,956
Restricted cash	1,070	--
Securities available-for-sale	--	3,550
Accounts receivable (net of allowance for doubtful accounts of $3,860 and $5,793, respectively)	209,144	108,075
Notes receivable	35,135	2,756
Materials, supplies and fuel	24,720	17,608
Derivative assets	36,393	38,144
Deferred income taxes	6,017	3,634
Other assets	8,020	12,384
Assets of discontinued operations	--	10,090
	400,310	226,197
Investments	18,707	59,895
Property, plant and equipment	1,890,266	1,564,664
Less accumulated depreciation and depletion	(414,003)	(328,325)
	1,476,263	1,236,339
Other assets:		
Derivative assets	2,406	6,407
Goodwill	33,685	28,693
Intangible assets	78,089	86,528
Other	25,709	18,342
	139,889	139,970
	$ 2,035,169	$ 1,662,401
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 207,047	$ 96,218
Accrued liabilities	53,753	39,085
Current maturities of long-term debt	23,448	35,904
Notes payable	340,500	360,450
Derivative liabilities	46,557	42,681

Liabilities of discontinued operations	--	8,820
	671,305	583,158
Long-term debt, net of current maturities	618,862	415,798
Deferred credits and other liabilities:		
Deferred income taxes	132,270	78,936
Derivative liabilities	8,419	7,119
Other	62,696	42,693
	203,385	128,748
Minority interest in subsidiaries	6,454	19,533
Commitments and contingencies (Notes 3, 12, 13, 17 and 21)		
Stockholders' equity:		
Preferred stock - no par Series 2000-A; 21,500 shares authorized; issued and outstanding: 5,177 shares in 2002 and 2001	5,549	5,549
Common stock equity-		
Common stock $1 par value; 100,000,000 shares authorized; issued: 27,102,351 shares in 2002 and 26,890,943 shares in 2001	27,102	26,891
Additional paid-in capital	246,997	241,454
Retained earnings	280,628	250,515
Treasury stock, at cost	(3,921)	(5,503)
Accumulated other comprehensive loss	(21,192)	(3,742)
	529,614	509,615
Total stockholders' equity	535,163	515,164
	$ 2,035,169	$ 1,662,401

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,	2002	2001	2000
		(in thousands)	
Operating activities:			
Net income available for common	$ 61,229	$ 87,550	$ 52,770
Adjustments to reconcile net income available for common to net cash provided by operating activities-			
(Income) loss from discontinued operations	2,637	(493)	(36)
Depreciation, depletion and amortization	69,738	53,811	32,624
Issuance of treasury stock for operating expense	2,252	4,243	--
Provision for valuation allowances	(2,935)	9,632	3,232
Net change in derivative assets and liabilities	(611)	2,498	(1,422)
Gain on sales of assets	--	(2,587)	(3,736)
Deferred income taxes	33,071	9,792	1,937
Undistributed earnings in associated companies	(2,972)	(9,287)	(3,672)
Minority interest	3,162	4,186	11,273
Accounting change	(896)	--	--
Change in operating assets and liabilities-			
Accounts receivable and other current assets	(102,482)	176,974	(208,078)
Accounts payable and other current liabilities	150,161	(157,061)	181,058
Other operating activities	6,420	(852)	1,691
	218,774	178,406	67,641
Investing activities:			
Property, plant and equipment additions	(233,074)	(378,465)	(134,855)
Payment for acquisition of net assets, net of cash acquired	(23,229)	(199,001)	(28,688)
Payment for acquisition of minority interest	(13,800)	(16,676)	--
Notes receivable - Mallon Resources	(33,815)	--	--
Other investing activities	(1,235)	2,429	186
	(305,153)	(591,713)	(163,357)

Financing activities:

Dividends paid on common stock	(31,116)	(28,517)	(23,527)
Common stock issued	5,084	168,522	3,854
Increase (decrease) in short-term borrowings, net	(18,945)	149,450	75,998
Long-term debt - issuance	223,135	144,610	60,082
Long-term debt - repayments	(32,527)	(13,960)	(1,330)
Other financing activities	(9,397)	(1,132)	(11,937)
	136,234	418,973	103,140
Increase in cash and cash equivalents	49,855	5,666	7,424
Cash and cash equivalents:			
Beginning of year	29,956	24,290	16,866
End of year	$ 79,811	$ 29,956	$ 24,290
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest (net of amount capitalized)	$ 41,404	$ 39,563	$ 31,094
Income taxes paid (refunded)	$ (31,353)	$ 40,374	$ 18,880
Noncash net assets acquired through issuance of common and preferred stock (Note 12)	$ 3,826	$ 3,628	$ 34,493

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 Paid-In Capital	Retained Earnings	Treasury Stock		Accumulated Other Comprehensive Amount(loss)	Total
	Shares	Amount			Shares	Amount		
				(in thousands)				
Balance at December 31, 1999	21,739	$21,739	$ 40,658	$162,239	368	$(8,030)	$ --	$216,606
Comprehensive Income:								
Net income	--	--	--	52,848	--	--	--	52,848
Other comprehensive income, net of tax:								
Unrealized loss on available for sale securities	--	--	--	--	--	--	(813)	(813)
Total comprehensive income	--	--	--	52,848	--	--	(813)	52,035
Dividends on preferred stock	--	--	--	(78)	--	--	--	(78)
Dividends on common stock	--	--	--	(23,527)	--	--	--	(23,527)
Issuance of common stock	1,563	1,563	32,784	--	--	--	--	34,347
Treasury stock acquired, net	--	--	--	--	13	(1,037)	--	(1,037)
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 income, net of tax:								
Unrealized gain on available for sale securities	--	--	--	--	--	--	1,438	1,438
Initial impact of adoption of SFAS 133, net of minority interest	--	--	--	--	--	--	(4,510)	(4,510)
Fair value adjustment on derivatives designated as cash flow hedges, net of minority								

interest	--	--	--	--	--	--	143	143
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 income, net of tax:								
Fair value adjustment on derivatives designated as cash flow hedges, net of minority interest	--	--	--	--	--	--	(8,639)	(8,639)
Minimum pension liability adjustment	--	--	--	--	--	--	(8,811)	(8,811)
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

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

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2002, 2001 and 2000

(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 integrated energy, regulated electric utility and communications. The Company operates its integrated 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, respectively, and Black Hills Energy Capital and its subsidiaries and Black Hills Generation 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 indirect subsidiaries Black Hills Fiber Systems, Black Hills FiberCom L.L.C. and Daksoft. For further descriptions of the Company’s business segments, see Note 16.

In 2002, the Company decided to sell its coal marketing business. The non-strategic assets were sold effective August 1, 2002.

In December 2000, the Company effected a holding company structure under the renamed holding company, Black Hills Corporation.

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 and certain subsidiaries in which the Company's ownership interest may be less than 50 percent but represents voting control. 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 $10.5 million, $11.2 million and $9.7 million in 2002, 2001 and 2000, 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 17, the Company and its subsidiaries made several acquisitions during 2002 and 2001. 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 Wyodak power plant as discussed in Note 11.

The Consolidated financial statements also include assets, liabilities and income from discontinued operations (See Note 18).

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 — $1.0 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, 2002 and 2001, the Company had regulatory assets of $4.4 million and $4.1 million and regulatory liabilities of $3.8 million and $4.2 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. 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.

Securities Available-for-Sale

The Company had investments in marketable securities at December 31, 2001 that were classified as available-for-sale securities and are carried at fair value in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The unrealized gain or loss each period resulting from the change between the securities' fair value and cost basis is included as a component of accumulated other comprehensive income in common stockholders' equity.

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, see Note 21 for additional information. The loan is due 60 days after the merger termination date, but in no case later than June 30, 2003. The note bears interest at a rate of prime plus 4.0 percent and is due on the loan termination date. At December 31, 2002, the interest rate was 8.25 percent.

Materials, Supplies and Fuel

As of December 31, 2002, all materials, supplies and fuel are stated at the lower of cost or market on a first-in, first-out basis. During 2001 and 2000, provisions of $1.4 million and $1.5 million, respectively, were charged to operations to write-down inventories at the Company's communications group to estimated net realizable value. Prior to October 26, 2002, natural gas and oil inventories held in energy marketing companies were stated at market.

The amounts and carrying basis by major class as of December 31 2002 and 2001 are provided as follows:

Major Classification	2002 Carrying Amount	2001 Carrying Amount
	(in thousands)	
Materials and supplies	$ 16,592	$ 12,226
Fuel for generation	2,073	1,496
Gas and oil held by energy marketing	6,055	3,886
Total materials, supplies and fuel	$ 24,720	$ 17,608

Derivatives and Hedging Activities

The Company accounts for its derivative and hedging activities in accordance with SFAS No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." 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.

The Company adopted SFAS 133 on January 1, 2001. Upon adoption, most of the Company's energy marketing activities previously accounted for under EITF 98-10 fell under the purview of SFAS 133. The effect of adoption on the energy marketing companies and risk management activities was not material because, unless otherwise noted, the energy marketing companies did not designate their risk management activities as hedge instruments. This "no hedge" designation resulted in these derivatives being measured at fair value and gains and losses recognized currently in earnings. This treatment under SFAS 133 was comparable to the accounting under EITF 98-10.

At January 1, 2001, the Company had certain non-trading energy contracts and interest rate swaps documented as cash flow hedges. These contracts were defined as derivatives under SFAS 133 and met the requirements for cash flow hedges. Because these contracts were documented as hedges prior to adoption, the transition adjustment was reported in accumulated other comprehensive income. The aggregated entry for these derivatives identified as cash flow hedges increased derivative assets by $0.9 million, increased the derivative liabilities by $11.2 million and decreased accumulated other comprehensive income by $10.3 million pre-tax.

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 9.1, 10.2 and 9.7 percent during 2002, 2001 and 2000, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $11.5 million, $7.5 million and $2.0 million in 2002, 2001 and 2000, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, together with removal cost 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.

Goodwill and Intangible Assets

Goodwill represents the excess of acquisition costs over the fair value of the net assets of acquired businesses and through 2001 was amortized on a straight-line basis over the estimated useful lives of such assets, which ranged from 8 to 25 years. Goodwill amortization was $1.5 million and $1.4 million for the years ended December 31, 2001 and 2000, respectively.

The cost of other acquired intangibles is amortized on a straight-line basis over their estimated useful lives. Amortization expense for intangible assets was $4.2 million, $2.6 million and $1.6 million in 2002, 2001 and 2000, respectively. Accumulated amortization was $15.5 million, $4.5 million and $1.9 million at December 31, 2002, 2001 and 2000, respectively.

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 2002, an $0.8 million impairment was recorded for intangible assets in our discontinued coal marketing operations. No impairment loss was recorded in continuing operations during 2002, 2001 or 2000.

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 abandonments 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 2002, 2001 or 2000.

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. For its Investment in Associated Companies (see Note 4), 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 is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed under the treasury stock method and is calculated to compute the dilutive effect of common stock equivalents which were primarily outstanding stock options and conversion of preferred shares. A reconciliation of Income from continuing operations and basic and diluted share amounts is as follows (in thousands):

	2002		2001		2000	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$63,193	--	$87,584	--	$52,812	--
Less: preferred stock dividends	(223)	--	(527)	--	(78)	--
Basic - available for common shareholders	62,970	26,803	87,057	25,374	52,734	22,118
Dilutive effect of:						
Stock options	--	91	--	223	--	86
Convertible preferred stock	223	148	527	148	78	56
Others	--	125	--	26	--	21
Diluted - available for common shareholders	$63,193	27,167	$87,584	25,771	$52,812	22,281

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):

	2002	2001	2000
Options to purchase common stock	381	45	113
Restricted stock	34	12	--
	415	57	113

Stock-based Compensation

At December 31, 2002, 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 6. 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):

	2002	2001	2000
Net income available for common stock, as reported	$ 61,229	$ 87,550	$ 52,770
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(990)	(705)	(338)
Pro forma net income	$ 60,239	$ 86,845	$ 52,432
Earnings per share:			
As reported -			
Basic			
Continuing operations	$ 2.35	$ 3.43	$ 2.39
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.28	$ 3.45	$ 2.39
Diluted			
Continuing operations	$ 2.33	$ 3.40	$ 2.37
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.26	$ 3.42	$ 2.37
Pro forma -			
Basic			
Continuing operations	$ 2.32	$ 3.40	$ 2.37
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.25	$ 3.42	$ 2.37
Diluted			
Continuing operations	$ 2.30	$ 3.37	$ 2.36
Discontinued operations	(0.10)	0.02	--
Change in accounting principle	0.03	--	--
Total	$ 2.23	$ 3.39	$ 2.36

Reclassifications

Realized and unrealized gains and losses under energy trading contracts in the energy marketing segment have been reclassified to be presented on a net basis in Operating revenues on the accompanying Consolidated Statements of Income in accordance with EITF Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” If the Company had reported these items on a gross basis, both operating revenues and fuel and purchased power costs would have been $1.2 billion, $1.0 billion and $1.3 billion higher for 2002, 2001 and 2000, respectively. The net presentation of these items rather than a gross presentation has no impact on operating income or net income.

Certain 2001 and 2000 amounts in the consolidated financial statements have been reclassified to conform to the 2002 presentation. These reclassifications had no effect on the Company’s common stockholders’ equity or results of operations, as previously reported.

Recently Adopted Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, “Business Combinations,” (SFAS 141) and No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). The Company has adopted SFAS 141, which requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. 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 of the change in accounting principle, net of tax at January 1, 2002, was a $0.9 million benefit. 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. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The Company adopted SFAS 142 on January 1, 2002.

The pro forma effects of adopting SFAS 142 for the years ended December 31, 2002, 2001 and 2000 are as follows (in thousands, except per share amounts):

	2002	2001	2000
Net income as reported	$ 61,452	$88,077	$52,848
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	61,311	88,077	52,848
Add: goodwill amortization	--	1,499	1,394
Adjusted net income	$ 61,311	$89,576	$54,242

	2002	2001	2000
Basic earnings per share	$ 2.28	$3.45	$2.39
Change in accounting principle	(0.03)	--	--
Change in accounting principle included in discontinued operations	0.02	--	--
Add goodwill amortization	--	0.06	0.06
Adjusted basic earnings per share	$ 2.27	$3.51	$2.45
Diluted earnings per share	$ 2.26	$3.42	$2.37
Change in accounting principle	(0.03)	--	--
Change in accounting principle included in discontinued operations	0.02	--	--
Add goodwill amortization	--	0.06	0.06
Adjusted diluted earnings per share	$ 2.25	$3.48	$2.43

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 (Note 18). 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.

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 year ended December 31, 2002, including the effects of adopting SFAS 142, but excluding amounts from discontinued operations, are as follows (in thousands):

	Goodwill	Other Intangible Assets
Balance at December 31, 2001, net of accumulated amortization	$ 28,693	$ 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	$ 33,685	$ 78,089

Intangible assets totaled $93.6 million, with accumulated amortization of $15.5 million at December 31, 2002 and $91.0 million, with accumulated amortization of $4.5 million at December 31, 2001. Intangible assets are primarily related to site development fees and above-market long-term contracts, and all have estimated useful lives ranging from 5 to 40 years, over which they continue to be amortized. Amortization expense for existing intangible assets for the next five years is expected to be approximately $4.2 million a year.

Goodwill additions during the year ended December 31, 2002, were from contingent consideration related to the July 7, 2000 acquisition of Indeck Capital Inc. (see Note 12).

Intangible asset additions during the year ended December 31, 2002 were primarily the result of a $9.3 million addition related to preliminary purchase allocations in the acquisition of additional ownership interest in the Harbor Cogeneration Facility (See Note 17). This intangible asset primarily relates to an acquired ownership of additional interest in a contract termination payment stream at the facility.

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 third quarter 2001 Las Vegas Cogeneration acquisition.

In addition, during the first quarter of 2002, the Company had a $0.8 million (pre-tax) impairment loss of certain intangibles at the Company's discontinued coal marketing business as a result of a weak coal market. The intangible assets are included in "Assets of discontinued operations" on the accompanying Consolidated Balance Sheets and the related impairment loss is included in "Income (Loss) from discontinued operations, net of taxes" on the accompanying Consolidated Statements of Income.

In August 2001, the FASB issued SFAS 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” SFAS 144 supersedes SFAS No. 121, “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of” (SFAS 121) and the accounting and reporting provisions of APB Opinion No. 30, “Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions” (APB 30). SFAS 144 establishes a single accounting model for long-lived assets to be disposed of by sale and resolves implementation issues related to SFAS 121. The Company adopted SFAS 144 effective January 1, 2002. Adoption did not have a material impact on the Company’s consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

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 is 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 is 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.

Upon adoption of SFAS 143 on January 1, 2003, the Company recorded an asset retirement obligation of $5.4 million in the balance sheet which represents the current estimated fair value of our obligation to plug oil and gas wells at the time of abandonment. The cumulative effect on earnings of adopting SFAS 143 was a charge of approximately $0.1 million representing the cumulative amounts of depreciation and changes in the asset retirement obligation due to the passage of time for historical accounting periods.

Pro forma net income and earnings per share have not been presented for the years ended December 31, 2002, 2001 and 2000 because the pro forma application of SFAS 143 to prior periods would result in pro forma net income and earnings per share not materially different from the actual amounts reported for those periods in the accompanying Consolidated Statements of Income.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 98-10, “Accounting for Contracts Involving Energy Trading and Risk Management Activities,” requires that energy trading contracts be accounted for at fair value. EITF 02-3 rescinds Issue No. 98-10 effective for any new contracts entered into after October 25, 2002. For energy trading contracts entered into through October 25, 2002, such contracts have 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 derivative, as defined by SFAS 133, are required to be accounted for at historical cost and the Company will report this as a cumulative effect of an accounting change. The Company’s energy contracts that qualify as derivatives will continue to be accounted for at fair value under SFAS 133.

EITF 02-3 requires that energy trading contracts and derivatives, whether settled financially or physically, be reported in the income statement on a net basis effective January 1, 2003.

Through December 31, 2002, the Company has presented the unrealized and realized gains and losses, whether or not settled financially or physically, from the activities of its energy marketing businesses, on a net basis in Operating Revenues on the Consolidated Statements of Income. As discussed below, this current presentation will be affected by the adoption of EITF 02-3.

The Company’s crude oil marketing operations previously met the definition of “energy trading activities” under EITF 98-10. Accordingly, substantially all crude oil 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 will no longer be recorded at fair value, since they do not meet the definition of derivatives as defined by SFAS 133, and will be recorded under the accrual method of accounting. In addition, this will affect the presentation of the related revenues and energy purchase expenses, because under current accounting principles generally accepted in the United States of America, the results of these contracts will need to be presented on a gross basis.

In addition to all of the contracts at the Company’s crude oil marketing operations no longer being recorded at fair value, certain contracts and physical positions at the Company’s natural gas marketing and trading operations will no longer be recorded at fair value since they do not meet the definition of a derivative under SFAS 133. Since we use transportation contracts and physical positions to economically hedge our natural gas portfolio, to the extent these items can no longer be accounted for at fair value, it will introduce volatility into future earnings of our natural gas marketing operations.

Upon adoption of EITF 02-3 on January 1, 2003, the Company recorded a charge for a cumulative effect of an accounting change totaling approximately $3.2 million, net of tax.

In November 2002, the FASB issued FASB Interpretation No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others” (Interpretation 45). Interpretation 45 clarifies the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. Interpretation 45 also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing certain types of guarantees. Certain types of guarantees are not subject to the initial recognition and measurement provisions of Interpretation 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of Interpretation 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor’s fiscal year-end. The guarantor’s previous accounting for guarantees issued prior to the date of the initial application of Interpretation 45 shall not be revised or restated. The disclosure requirements in Interpretation 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company will apply the initial recognition and initial measurement provisions of Interpretation 45 to guarantees issued or modified after December 31, 2002. For more information on the Company’s guarantees and disclosure requirements of Interpretation 45, as applicable to the Company, see Note 3.

In December 2002, the FASB issued SFAS No. 148, “Accounting for Stock-Based Compensation—Transition and Disclosure” (SFAS 148). SFAS 148 amends SFAS 123, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Certain amendments to SFAS 123 are effective for financial statements for fiscal years ending after December 15, 2002. The Company currently follows the accounting provisions of APB 25 for stock-based compensation and provides the pro forma disclosures required under SFAS 123 as amended by SFAS 148.

In connection with the January 2003 FASB Emerging Issues Task Force meeting, the FASB was requested to reconsider an interpretation of SFAS No. 133. The interpretation, which is contained in the Derivatives Implementation Group's C11 guidance, relates to the pricing of contracts that include broad market indices. In particular, that guidance discusses whether the pricing in a contract that contains broad market indices (e.g., CPI) could qualify as a normal purchase or sale (the normal purchase or sale term is a defined accounting term, and may not, in all cases, indicate whether the contract would be "normal" from an operating entity viewpoint). The Company is currently re-evaluating which contracts, if any, that have previously been designated as normal purchases or sales would now not qualify for this exception. The Company is currently evaluating the effects that this guidance will have on its results of operations and financial position.

(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 8 and 9.

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 a formalized 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 that 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/or 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 98-10, SFAS 133, and for contracts entered into after October 25, 2002, in accordance with EITF 02-3. 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:

	2002		2001	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of MMBtu's)				
Natural gas basis swaps purchased	72,340	1	9,882	1
Natural gas basis swaps sold	72,329	1	10,696	1
Natural gas fixed-for-float swaps purchased	10,675	1	10,646	2
Natural gas fixed-for-float swaps sold	17,934	1	11,815	2
Natural gas swing swaps purchased	--	--	465	1
Natural gas swing swaps sold	--	--	930	1
Natural gas physical purchases	42,813	1.25	13,159	1
Natural gas physical sales	41,654	1	19,339	1

Derivatives and certain natural gas marketing activities were marked to fair value on December 31, 2002 and 2001, 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, 2002 and 2001 are as follows (in thousands):

	Current Assets	Non-current Assets	Current Liabilities	Non-current Liabilities	Unrealized Gain
December 31, 2002	$ 29,559	$ 2,406	$ 28,535	$ 409	$ 3,021
December 31, 2001	$ 29,755	$ 661	$ 25,437	$ 953	$ 4,026

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 have historically fallen under the purview of EITF 98-10 and as such, all crude oil contracts entered into on or before October 25, 2002, have 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 do not meet the definition of derivatives under SFAS 133 and hence none of these contracts entered into after October 25, 2002 will be marked-to-market in future financial statements.

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

	2002		2001	
	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
(thousands of barrels)				
Crude oil purchased	4,081	0.5	3,139	1
Crude oil sold	4,150	0.5	3,142	1

On December 31, 2002 and 2001, crude oil contracts entered into on or before October 25, 2002 were marked to fair value and the gains and/or losses recognized in earnings. 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
December 31, 2001	$ 6,267	$ --	$ 5,496	$ --	$ 771

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 and are routinely reviewed by its Audit Committee.

Any 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, 2002, 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, 2002, 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, 2002 and 2001, 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, 2002								
Crude oil swap	360,000	1	$ --	$ --	$ 976	$ --	$ (914)	$ (62)
Natural gas swaps	1,650,000	1	58	--	744		(686)	--
	--	--	$ 58	$--	$ 1,720	$ --	$ (1,600)	$ (62)
December 31, 2001								
Crude oil swaps	90,000	1	$ 529	$ --	$ --	$ --	$ 529	$ --
Natural gas swaps	1,216,000	1	1,593	--	--	--	1,463	130
	--	--	$2,122	$ --	$ --	$ --	$ 1,992	$ 130

*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. During 2002, the Company recorded a $0.1 million loss due to ineffectiveness for certain crude oil swaps due to basis risk.

All existing hedges at December 31, 2002 expire during the year ended December 31, 2003. The unrealized earnings gains or losses currently recorded in accumulated other comprehensive income are expected to be realized in earnings during 2003. Based on December 31, 2002 market prices, $1.6 million loss will be realized and reported in earnings during 2003. These estimated realized losses for 2003 were calculated using December 31, 2002 market prices. Estimated and actual realized losses will likely change during 2003 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, will 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 17). 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, 2002, these hedges met effectiveness testing criteria and retained their cash flow hedge status. At December 31, 2002, the Company had $237.3 million of notional amount floating-to-fixed interest rate swaps, having a maximum term of four years and a fair value of $(18.3) million. These hedges are substantially effective and any ineffectiveness was immaterial.

On December 31, 2002 and 2001, 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, 2002								
Swaps on project financing	$212,256	5.98%	4	$ --	$ --	$ 9,345	$ 7,844	$ (17,189)
Swaps on corporate debt	25,000	5.28%	1	--	--	947	166	(1,113)
	$237,256	--	-	$ --	$ --	$10,292	$ 8,010	$ (18,302)
December 31, 2001								
Swaps on project financing	$316,397	5.85%	4	$ --	$ 5,746	$10,212	$ 5,949	$ (10,415)
Swaps on corporate debt	75,000	4.45%	3	--	--	1,535	217	(1,752)
	$391,397	--	-	$ --	$ 5,746	$11,747	$ 6,166	$ (12,167)

The Company anticipates a portion of unrealized losses recorded in accumulated other comprehensive income will be realized as increased interest expense in 2003. Based on December 31, 2002 market interest rates, $10.3 million will be realized as additional interest expense during 2003. Estimated and realized amounts will likely change during 2003 as market interest rates change.

At December 31, 2002, the Company had $770.0 million of outstanding, floating-rate debt of which $532.8 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 $5.3 million.

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 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 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 energy marketing, production, and generation activities, the Company attempts to mitigate credit risk by conducting a majority of 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 guaranties, 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 68 percent of the credit exposure was with investment grade companies. For the 32 percent credit exposure with non-investment grade rated counterparties, approximately 62 percent of this exposure was supported through letters of credit, prepayments, parental guarantees and asset liens.

(3) 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, the Company will begin recording a liability for the fair value of the obligation it has undertaken for guarantees issued after December 31, 2002. The liability recognition requirements of FASB Interpretation No. 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, 2002 we had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2002	Year Expiring

	(in thousands)	
Completion guarantee for the expanded facilities under a construction loan for Black Hills Colorado	$135,000	2003
Guarantee of secured financing for the Las Vegas II project	50,000	2003
Guarantee payments under certain energy marketing derivative, power and gas agreements	7,500	2003
Guarantee of obligation of Las Vegas Cogen II under an interconnection and operation agreement	750	2005
Guarantee performance of Black Hills Generation under a power sales agreement	5,000	2004
Guarantee obligations under the Wygen Plant Lease	89,400	2008
Guarantee payment and performance under credit agreements for two combustion turbines	32,000	2010
Indemnification for subsidiary reclamation/surety bonds	30,720	2003
	$350,370	--

The Company has guaranteed the payment of $135 million of debt as of December 31, 2002, for its wholly-owned subsidiary, Black Hills Colorado, LLC until conversion of its construction loan to a term loan which occurred on January 17, 2003 at which time the guarantee expired. This debt is recorded on the Company's Consolidated Balance Sheets.

The Company has provided a completion guarantee and has guaranteed the payment of $50 million of project debt for the Las Vegas II project, for its wholly-owned subsidiaries, Las Vegas Cogeneration II, LLC and Las Vegas Cogeneration Energy Financing Company, LLC. The Las Vegas II unit was placed in service in January 2003. This debt is recorded on the Company's Consolidated Balance Sheets and is due May 26, 2003.

The Company has guaranteed $7.5 million of commodity related payments for its energy marketing subsidiary, Enserco Energy Inc. These guarantees were provided to counterparties in order to facilitate physical and financial transactions in energy commodities and related services. To the extent liabilities exist under the commodity- related contracts subject to these guarantees, such liabilities are included in the Consolidated Balance Sheets. Of the $7.5 million of guarantees, $4.5 million expire on June 1, 2003 and $3.0 million expire on December 31, 2003.

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 LV II unit. 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 guaranteed up to $5 million for the performance of its wholly-owned subsidiary, Black Hills Generation, under a power sales agreement on the Wygen plant. The guarantee will expire in March 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 also guaranteed the obligations of Black Hills Generation under the agreement for lease and lease for the Wygen plant. The lease is currently accounted for as an off-balance sheet transaction, therefore there are no liabilities associated with the lease on the consolidated financial statements. For additional information on the lease, see Note 12. 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, 2002, the Company's maximum obligation under the guarantee is $89.4 million (83.5 percent of $107.1 million, the cost incurred for the Wygen plant as December 31, 2002). The initial term of the lease is five years with two five-year renewal options.

The Company has guaranteed the payment of $27.5 million of debt of Black Hills Generation and $4.5 million of debt for another of its wholly-owned subsidiaries, Black Hills Energy Capital, Inc. The debt is recorded on the Company's Consolidated Balance Sheets and is due December 18, 2010.

In addition, at December 31, 2002, the Company had guarantees in place totaling approximately $30.7 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.

(4) 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 $11.0 million and $10.0 million at December 31, 2002 and 2001, 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, 2002, the funds had assets of $160.7 million, liabilities of $0.7 million and net income of $25.8 million. As of, and for the year ended December 31, 2001, the funds had assets of $215.1 million, liabilities of $0.7 million and net income of $37.2 million.

- 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 $3.4 million and $3.9 million as of December 31, 2002 and 2001, 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, 2002, these projects had assets of $24.5 million, liabilities of $17.1 million and a net income of $0.7 million. As of, and for the year ended December 31, 2001, these projects had assets of $25.6 million, liabilities of $19.0 million and a net loss of $(0.4) million.

(5) PROPERTY, PLANT AND EQUIPMENT

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

Regulated

	2002	2001	Lives (in years)
Electric plant:			
Production	$313,725	$282,462	25-58
Transmission	94,683	90,469	35-50
Distribution	143,629	137,109	20-40
General	31,953	29,662	7-40
Total electric plant	583,990	539,702	--
Less accumulated depreciation and amortization	201,614	186,303	--
Electric plant net of accumulated depreciation and amortization	382,376	353,399	--
Construction work in progress	19,212	29,666	--
Net electric plant	$401,588	$383,065	--

2002

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	$ 63,125	$ 31,630	$ 31,495	$ 4,102	$ 35,597	3-39
Oil and 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	718,345	90,541	627,804	199,769	827,573	3-40
Communications	151,105	29,418	121,687	251	121,938	3-31.5
Other	714	149	565	688	1,253	5-7
	$ 1,078,085	$ 212,389	$ 865,696	$ 208,979	$ 1,074,675	--

2001

	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	$ 57,414	$ 28,014	$ 29,400	$ 6,178	$ 35,578	3-39
Oil and gas	104,926	52,629	52,297	--	52,297	3-40
Energy marketing	660	257	403	--	403	3-5
Power generation	500,435	44,381	456,054	195,910	651,964	3-40
Communications	129,483	16,739	112,744	265	113,009	3-31.5
Other	25	2	23	--	23	5-7
	$ 792,943	$ 142,022	$ 650,921	$ 202,353	$ 853,274	--

(6) COMMON STOCK

Equity Compensation Plans

During 2001, the Company completed a public offering of its common stock through which approximately 3.4 million shares were sold at $52 per share. Net proceeds were approximately $163 million after commissions and expenses. The proceeds were used to repay a portion of current indebtedness under revolving credit facilities, to fund various power plant construction costs and for general corporate purposes.

The Company has several employee equity compensation plans, which allow for the granting of stock, restricted stock, 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 832,890 shares available to grant at December 31, 2002. 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, 2002, 2001 and 2000, and changes during the years then ended are as follows:

	2002		2001		2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	992,872	$26.55	914,917	$23.43	431,450	$21.35
Granted	211,985	30.04	203,000	37.09	492,500	25.22
Forfeited	(34,838)	33.52	(30,834)	22.13	(4,000)	23.25
Exercised	(127,030)	21.20	(94,211)	20.41	(5,033)	21.33
Balance at end of year	1,042,989	$27.68	992,872	$26.55	914,917	$23.43
Exercisable at end of year	566,654	$25.36	445,252	$22.76	292,891	$20.43

Details of outstanding options at December 31, 2002 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 $20.54	67,250	$ 18.27	6.8 years	67,250	$ 18.27
$20.55 to $24.41	462,754	$ 22.25	8.2 years	351,583	$ 22.38
$24.42 to $28.27	120,169	$ 25.17	9.4 years	18,502	$ 25.13
$28.28 to $32.14	130,500	$ 30.91	9.7 years	45,979	$ 30.76
$32.15 to $36.01	116,985	$ 34.46	9.3 years	3,333	$ 33.19
$36.02 to $39.88	102,165	$ 37.80	9.1 years	65,180	$ 37.75
$ 55.36	43,166	$ 55.36	8.7 years	14,827	$ 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:

	2002	2001	2000
Weighted average fair value of options at grant date	$ 6.63	$ 10.77	$ 3.88
Weighted average risk-free interest rate	4.17%	5.92%	6.30%
Weighted average expected price volatility	39.09%	34.92%	20.60%
Weighted average expected dividend yield	3.86%	2.90%	4.20%
Expected life in years	7	10	10

For a discussion of the effect on earnings per common share for the years ended December 31, 2002, 2001 and 2000, 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 17,496, 48,368 and 21,394 shares of common stock under the ESPP Plan in 2002, 2001 and 2000, respectively. At December 31, 2002, 160,312 shares are reserved and available for issuance under the ESPP Plan. The fair value per share of shares sold in 2002 was $26.06 on the offering date.

During 2001, the Company issued a total of 36,550 common shares as a stock bonus award to its non-officer employees. The bonus was grossed up to cover related employee taxes. The total pre-tax compensation charge recognized by the Company was $1.9 million, which is based on the market value of the stock on the grant date. Additionally, approximately 14,500 common shares will be issued at the two-year anniversary date of the original award, contingent on certain vesting restrictions. Pre-tax compensation cost related to this portion of the award is estimated to be $0.7 million and is being expensed over the two-year vesting period.

The Company issued 26,047 and 12,177 restricted common shares to certain officers in 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 $399,000 in 2002 and $131,000 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 66,882 new shares in 2002 at a weighted average price of $28.65 and purchased shares on the open market in 2001 and 2000. At December 31, 2002, 1,223,915 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 $425 million plus 50 percent of our aggregate consolidated net income since April 1, 2002. As of December 31, 2002, we were in compliance with the above covenants.

(7) PREFERRED STOCK

The Company has 25,000,000 authorized shares of no-par preferred stock.

During 2002, 2001 and 2000, the Company issued 5,177 preferred shares in the Indeck Capital acquisition and the related "earn-out" provisions (see Note 12). 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.

(8) LONG-TERM DEBT

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

	2002	2001
First mortgage bonds:		
6.50% due 2002	$ --	$ 15,000
9.00% due 2003	1,113	2,176
8.06% due 2010	30,000	30,000
9.49% due 2018	4,550	4,840
9.35% due 2021	31,635	33,300
8.30% due 2024	45,000	45,000
7.23% due 2032	75,000	--
	187,298	130,316
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 3.41% due 2010(a)(c) (d)	32,000	--
Term Credit Agreement due 2004(b)(c)	35,000	--
Other(c)	3,823	3,870
	95,323	28,370
Project financing floating rate debt(c):		
Fountain Valley project at 3.30%(d) due 2006	138,661	144,581
Hudson Falls at 3.15%(d) due 2010	64,278	69,479
South Glens Falls at 3.15%(d) due 2009	21,750	24,008
Valmont and Arapahoe at 3.31%(d) due 2007	135,000	54,948
	359,689	293,016
Total long-term debt	642,310	451,702
Less current maturities	(23,448)	(35,904)

Net long-term debt	$ 618,862	$ 415,798

(a) Floating rate debt, $27.5 million secured by Gillette combustion turbine and $4.5 million secured by a spare LM6000 turbine.

(b) Unsecured floating rate debt based on prime rate plus 0.25 percent or LIBOR plus 1.25 percent.

(c) Approximately 49 percent of the December 31, 2002 balance has been hedged with interest rate swaps moving the floating rates to fixed rates with a weighted average interest rate of 5.98 percent (see Note 2-Risk Management Activities).

(d) Interest rates are presented as of December 31, 2002.

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, 2002. Some of the subsidiaries debt agreements provide that approximately $50 million of the subsidiaries' cash balance at December 31, 2002 may not be distributed to the parent company.

Scheduled maturities of long-term debt for the next five years are: $23.4 million in 2003, $60.9 million in 2004, $27.4 million in 2005, $139.8 million in 2006 and $127.1 million in 2007.

(9) NOTES PAYABLE

The Company has committed lines of credit with various banks totaling $395 million at December 31, 2002 and $400 million at December 31, 2001. At December 31, 2002, these lines consist of a $195 million revolving credit facility with a term of 364 days, which terminates August 27, 2003 and a $200 million revolving credit facility with a term of three years, which terminates on August 27, 2004. The Company had $290.5 million of borrowings and $40.3 million of letters of credit and $360 million of borrowings and $33.0 million of letters of credit issued on the lines at December 31, 2002 and 2001, 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 (4.25 percent at December 31, 2002) or (ii) on a London Interbank Offered Rate (LIBOR) based borrowing rate or LIBOR plus 0.75 percent to LIBOR plus 0.8 percent. The one-month LIBOR rate at December 31, 2002 was 1.38 percent. In addition to interest on outstanding borrowings, the credit facilities contain a 0.20 percent to 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.

The Company also has a $50 million short-term secured financing on the Las Vegas II project with a "backstop" guarantee provided by the Company. The debt matures May 26, 2003 and has a variable interest rate. The interest rate was 4.42 percent at December 31, 2002.

In addition to the above lines of credit, at December 31, 2002, 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 and its other subsidiaries provide no guarantees to the lender. At December 31, 2002 and 2001, there were outstanding letters of credit issued under the facility of $46.7 million and $36.2 million, respectively, with no borrowing balances on the facility.

Black Hills Energy Resources (BHER) has a $25.0 million uncommitted, discretionary credit facility secured by all of its assets. The transactional line of credit provides credit support for the purchases of crude oil of BHER. The Company and its other subsidiaries provide no guarantees to the lender. At December 31, 2002 and 2001, BHER had letters of credit outstanding of $13.5 million and $4.4 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, 2002. In addition, certain of the Company's interest rate swap agreements with a $25 million notional amount at December 31, 2002 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. Some of the facilities previously contained rating triggers whereby the Company was required to maintain a credit rating of at least BBB- from Standard & Poor's or Baa3 from Moody's Investor Service. These facilities were amended during the second quarter of 2002 to remove the 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.

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	2002		2001	
	(in thousands)			
	Carrying Amount	Fair Value	Carrying Amount	Fair Value

Cash and cash equivalents	$ 79,811	$ 79,811	$ 29,956	$ 29,956
Restricted cash	$ 1,070	$ 1,070	$ --	$ --
Securities available-for-sale	$ --	$ --	$ 3,550	$ 3,550
Derivative financial instruments - assets	$ 38,799	$ 38,799	$ 44,551	$ 44,551
Derivative financial instruments - liabilities	$ 54,976	$ 54,976	$ 49,800	$ 49,800
Notes payable	$340,500	$340,500	$360,450	$360,450
Long-term debt	$642,310	$666,191	$451,702	$469,787

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.

Securities Available-for-Sale

The fair value of the Company's investments equals the quoted market price. The Company did not have any available-for-sale securities as of December 31, 2002. The Company has classified all of its marketable securities as available-for-sale as of December 31, 2001. An unrealized gain on the Company's investments of $1.4 million was recorded as of December 31, 2001.

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 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.

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(11) JOINTLY OWNED FACILITY

The Company owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 330 megawatt coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant. The Company 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, 2002, the Company's investment in the Plant included $71.5 million in electric plant and $26.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company's share of direct expenses of the Plant was $5.5 million, $5.9 million and $5.6 million for the years ended December 31, 2002, 2001 and 2000, respectively, and is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income. As discussed in Note 12, 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 1,500,000 tons of coal each year of the contract term, subject to adjustment for planned outages. Wyodak Resources' sales to the Plant were $19.0 million, $21.0 million and $23.2 million for the years ended December 31, 2002, 2001 and 2000, respectively.

(12) COMMITMENTS AND CONTINGENCIES

Off-Balance Sheet Arrangement

The Company's subsidiary, Black Hills Generation, has entered into agreements with Wygen Funding, Limited Partnership, an unrelated, unconsolidated special purpose entity (SPE), to lease the Wygen plant, a 90 megawatt coal-fired power plant under construction in Campbell County, Wyoming. Wygen Funding owns the Wygen plant, has financed the project and will lease it to Black Hills Generation upon completion of construction. Lease payments are expected to commence in the second quarter of 2003. The financing arrangement was entered into due to its low cost of financing. The SPE has an aggregate financing commitment from equity and debt participants of $140 million. The Wygen plant is the only asset that the SPE owns. The initial lease term 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 project. At the end of each lease term, Black Hills Generation may renew the lease, purchase the facility, or sell the facility on behalf of the SPE, to an independent, third party. If the project is sold and the proceeds from the sale are insufficient to repay the investors, we will be required to make a payment to the SPE of the shortfall up to 83.5 percent of the adjusted acquisition cost. The Company has guaranteed the obligations of Black Hills Generation to the SPE.

As of December 31, 2002, costs incurred totaled $107.1 million, and the total costs for the completed facility are expected to be $130 — $140 million. The lease is currently considered an operating lease for financial accounting purposes, therefore neither the facility nor the related obligations are reported on the Company's Consolidated Balance Sheets. The lease is a LIBOR based variable rate obligation. Consequently, as market rates increase, the payments under this lease will also increase. Annual payments of approximately $3.5 million represent future minimum payments under the first five-year lease term calculated using an effective borrowing rate of 2.5 percent (the rate in effect at December 31, 2002). A one percent increase in the borrowing rate will increase the annual lease payment by approximately $1.4 million.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities". Under the new accounting interpretation, the Company will be required to consolidate the SPE by July 1, 2003, unless the transaction is restructured. The Company does not currently plan on restructuring the lease. The effect of consolidating the SPE into the Company's consolidated financial statements would be to record both the Wygen asset and its related debt on the Company's Consolidated Balance Sheets which will be in the range of $130 — $140 million at completion of construction. In addition, the net effect of consolidating the income statement of the SPE would be to recognize the depreciation and interest expense of the SPE in place of recognizing lease expense which is estimated to have approximately a $3.5 million pre-tax negative annual effect to pre-tax income based on a 40 year depreciable life.

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, 2001, $3.6 million has been paid under the earn-out. On December 31, 2002, additional consideration of $3.8 million was earned and payable. 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 Agreement – 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 $10.9 million in 2002 (net of a $1.3 million refund for prior years), $13.9 million in 2001 and $14.6 million in 2000.

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 (PSCC) 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 generally accepted accounting principles 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 contract is a tolling arrangement in which the Company assumes no fuel price risk. In addition, the Company entered into a ten year contract with CLF&P for 60 megawatts of contingent capacity from the 90 megawatt Wygen plant, currently under construction. Twenty megawatts of the remaining capacity of this plant has been sold under a ten year contract with the Municipal Energy Agency of Nebraska.
- The Company has a ten year power sales contract with the Municipal Energy Agency of Nebraska for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant.
- The Company has secured long-term contracts for the output of the 277 megawatt Las Vegas facility. The 53 megawatt Las Vegas I plant is contracted with Nevada Power through 2024. The 224 megawatt Las Vegas II facility was completed at year end and is under a tolling arrangement with Allegheny Energy Supply that expires in 2017.
- Various long-term contracts with Niagara Mohawk Power Corporation have been entered into to sell the output of several of the Company's hydroelectric projects located in upstate New York. The Company's net ownership of capacity under contract is approximately 21 megawatts with contracts expiring between 2029 and 2035. There are additional contracts on plants with a net ownership capacity of approximately 21 megawatts that expire during 2003.
- The Company has entered into a five year tolling agreement with Southern California Edison for 100 megawatts of capacity and power 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.

Reclamation Liability

Under its mining permit, Wyodak Resources is required to reclaim all land where it has mined coal reserves. The cost of reclaiming the land is accrued as the coal is mined. While the reclamation process takes place on a continual basis, much of the reclamation occurs over an extended period after the area is mined. Approximately $0.9 million, $0.8 million and $0.7 million was charged to operations as reclamation expense in 2002, 2001 and 2000, respectively. Accrued reclamation costs included in Other in Deferred credits and other liabilities on the accompanying Consolidated Balance Sheets were approximately $18.5 million and $18.2 million at December 31, 2002 and 2001, respectively.

Legal Proceedings

Fires

In September 2001 a fire occurred in the southwestern Black Hills of South Dakota. It is alleged that the fire occurred when a high voltage electrical span maintained by the Company's electric utility subsidiary 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 the Company 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 injury to timber, fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. It is expected that substantially similar claims will be asserted against the Company by the United States Forest Service. The Company's investigation into the cause and origin of the fire is still pending. The total amount of damages claimed by the State of South Dakota is not specified in the complaint. 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. Before being contained more than eight days later, the fire consumed approximately 11,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 20 structures. 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 the Company's electric utility subsidiary.

On September 6, 2002, the State of South Dakota commenced litigation against the Company, 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 is asserted with respect to the claim for injury to timber. The total amount of alleged damages is not specified.

On March 3, 2003, the United States of America filed a similar suit against the Company, in the United States District Court, District of South Dakota, Western Division. The federal government 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. The total amount of alleged federal damages is not specified.

The Company is completing its own investigation of the fire cause and origin and has requested access to the materials that form the basis for the assertions of state and federal fire investigators. The Company's investigation is not complete, but based on information currently available, the Company expects to deny all claims and vigorously defend any and all claims brought by governmental or private parties.

Although we cannot predict the outcome of our investigations or the viability of potential claims based on information currently available, management believes that any such claims, if determined adversely to us, will not have a material adverse effect on our 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 Facility from an affiliate of Enron. The partnership is called Las Vegas Cogeneration, L.P. 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 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 Nevada Power Company 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.

Recently FERC issued an order announcing an investigation to determine whether Enron's ownership of the Las Vegas Cogeneration Facility violated the qualifying facility regulations under PURPA. In addition, the SEC recently 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 does 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 rules with respect to the Las Vegas Cogeneration Facility, 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. The Company has the right to seek indemnification from the prior owner. While the prior owner does not appear among the Enron subsidiaries and affiliates currently in bankruptcy, the Enron bankruptcy could impair the Company's ability to enforce a claim for indemnification. Because FERC has only recently begun its investigation, the Company cannot predict the outcome of FERC's investigation. However, based upon information currently available, management does not believe that any refunds, fines or penalties resulting from the investigation will materially affect the Company's financial condition or results of operations.

Settlement

On April 3, 2001, the Company reached a settlement of ongoing litigation with PacifiCorp filed in the United States District Court, District of Wyoming, (File No. 00CV-155B). The litigation concerned 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, with prejudice, coupled with the execution of several new coal-related agreements between the parties discussed below. The Company believes the value of the Settlement Agreements is equal to the net present value of the litigated Further Restated and Amended Coal Supply Agreement.

<u>New Restated and Amended Coal Supply Agreement:</u> Effective January 1, 2001, 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). The New Agreement began on January 1, 2001, and extends to December 31, 2022. Under the New Agreement, the Company received an extension of sales beyond the June 8, 2013 term of the former Coal Supply Agreement. PacifiCorp will receive a price reduction for each ton of coal purchased. The minimum purchase obligation under the New Agreement increased to 1,500,000 tons of coal for each calendar year of the contract term, subject to adjustment for planned outages. The New Agreement further provided for a special one-time payment by PacifiCorp in the amount of $7.3 million, which was received in August 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.

<u>Coal Option Agreement:</u> The Company has entered into a coal option agreement with PacifiCorp, which began June 12, 2002, and extends until December 31, 2009. The agreement provides that PacifiCorp shall purchase 1,800,000 tons of coal during the period of June 12, 2002 through December 31, 2003 at a fixed price, and 900,000 tons of coal in the years 2004 through 2007 at a variable price based on a Coal Daily spot price. The agreement further provides the Company with a "put" option for 2004 through 2009 under which the Company may sell to PacifiCorp up to 100,000 tons of coal from the Wyodak Mine at a market based price from 2004 through 2007. For each calendar year from January 1, 2008 through December 31, 2009, the put option is increased to a maximum of 1,000,000 tons at a market based price.

<u>Sale of North Conveyor System:</u> The Company 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.

(13) 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.

Net pension (income) expense for the Plan was as follows:

	2002	2001	2000
		(in thousands)	
Service cost	$ 979	$ 945	$ 967
Interest cost	3,135	3,080	2,885
Expected return on assets	(4,206)	(5,814)	(5,257)
Amortization of transition amount	--	--	(90)
Amortization of prior service cost	231	231	231
Recognized net actuarial (gain) loss	102	(556)	(537)
Net pension (income) expense	$ 241	$ (2,114)	$ (1,801)
Actuarial assumptions:			
Discount rate-			
Used for net periodic pension cost	7.50%*	7.50%	7.50%
Used to value pension (liability)/asset at year-end	6.75%	7.50%	7.50%
Expected long-term rate of return on assets	10.50%**	10.50%	10.50%
Rate of increase in compensation levels	5.0%***	5.0%***	5.0%

*The discount rate used for net periodic pension cost was changed from 7.50 percent in 2002 to 6.75 percent for the calculation of the 2003 net periodic pension cost. This change is expected to increase pension costs in 2003 by approximately $0.4 million.

**The expected rate of return on plan assets was changed from 10.5 percent to 10 percent for the calculation of the 2003 net periodic pension cost. This change is expected to increase pension costs in 2003 by approximately $0.2 million.

***The rate of increase in compensation levels was changed in 2001 from a single rate assumption for all ages to

an age-based salary scale assumption resulting in a weighted average increase of 5.0 percent.

A reconciliation of the beginning and ending balances of the projected benefit obligation is as follows:

	2002	2001
	(in thousands)	
Beginning projected benefit obligation	$ 43,016	$ 41,314
Service cost	979	945
Interest cost	3,135	3,080
Actuarial (gain) loss	951	(167)
Discount rate change	4,926	--
Benefits paid	(2,368)	(2,156)
Amendments	249	--
Net increase	7,872	1,702
Ending projected benefit obligation	$ 50,888	$ 43,016

A reconciliation of the fair value of Plan assets as of October 1 of each year is as follows:

	2002	2001
	(in thousands)	
Beginning market value of plan assets	$ 41,268	$ 56,560
Benefits paid	(2,368)	(2,156)
Investment loss	(6,463)	(13,136)
Ending market value of plan assets	$ 32,437	$ 41,268

Funding information for the Plan as of October 1 of each year was as follows:

	2002	2001
	(in thousands)	
Fair value of plan assets	$ 32,437	$ 41,268
Projected benefit obligation	(50,888)	(43,016)
Funded status	(18,451)	(1,748)
Unrecognized:		
Net loss	21,971	5,527
Prior service cost	1,841	1,823
Net amount recognized	$ 5,361	$ 5,602
Amounts recognized in statement of financial position consist of:		
Net pension (liability) asset	$ (8,954)	$ 5,602
Intangible asset	1,841	--
Accumulated other comprehensive loss	12,474	--
Net amount recognized	$ 5,361	$ 5,602
Accumulated benefit obligation	$ 41,391	$ 35,695

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) requires 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. This liability represents the amount by which the accumulated benefit obligation exceeds the sum of the fair market value of plan assets and accrued amounts previously recorded. The additional liability may be offset by an intangible asset to the extent of previously unrecognized prior service cost. The intangible asset of $1.8 million at December 31, 2002 is included in the line item Other in Other Assets in the Consolidated Balance Sheets. The remaining amount of $12.5 million is recorded as a component of stockholders' equity, net of related tax benefits of $4.4 million, in the line item Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheet at December 31, 2002. Supplemental Nonqualified Defined Benefit Retirement Plan The Company has various supplemental retirement plans for outside directors and key executives of the Company. The plans are nonqualified defined benefit plans. Expenses recognized under the plans were $0.8 million during 2002 and $0.5 million during 2001 and 2000. The following table summarizes the accumulated benefit obligation and projected benefit obligation of the unfunded plan at December 31 (in thousands):

	2002	2001
Accumulated benefit obligation	$ 5,125	$ 3,324
Projected benefit obligation	$ 11,303	$ 5,826

The provisions of SFAS 87 required the Company to record an additional minimum liability of $1.1 million at December 31, 2002. This amount is included in Deferred credits and other liabilities, Other on the accompanying Consolidated Balance Sheets. This liability represents the amount by which the accumulated benefit obligation exceeds the sum of the fair market value of plan assets and accrued amounts previously recorded. The amount of $1.1 million is recorded as a component of stockholders' equity, net of related tax benefits of $0.4 million, in the line item Accumulated other comprehensive loss on the accompanying Consolidated Balance Sheets at December 31, 2002.

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 net periodic postretirement cost was as follows:

	2002	2001	2000
		(in thousands)	
Service cost	$ 284	$ 289	$ 282
Interest cost	519	507	523
Amortization of transition obligation	150	150	150
Amortization of prior service cost	(24)	--	--
Loss	35	21	68
	$ 964	$ 967	$ 1,023

Funding information as of October 1 was as follows:

2002	2001
(in thousands)	

Accumulated postretirement benefit obligation:		
Retirees	$ 3,376	$ 3,186
Fully eligible active participants	1,836	1,803
Other active participants	3,435	3,963
Unfunded accumulated postretirement benefit obligation	8,647	8,952
Unrecognized net loss	(2,202)	(2,792)
Unrecognized prior service cost	336	--
Unrecognized transition obligation	(1,498)	(1,648)
Contributions	(53)	--
Accrued postretirement cost	$ 5,230	$ 4,512

For measurement purposes, a 12.0 percent annual rate of increase in healthcare benefits was assumed for 2002; the rate was assumed to decrease gradually to 5.0 percent in 2009 and remain at that level thereafter. The healthcare cost trend rate assumption has a significant effect on the amounts reported. A one percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 20.6 percent and the net periodic postretirement benefit obligation $1.6 million or 18.2 percent. A one percent decrease would reduce the service and interest cost by $0.1 million or 16.8 percent and decrease the net periodic postretirement benefit obligation $1.2 million or 14.4 percent. The weighted-average discount rate used in determining the accumulated postretirement benefit obligation was 6.75 percent for 2002 and 7.50 percent for 2001.

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. Effective January 1, 2000 (May 1, 2000 for employees covered by the collective bargaining agreement), 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 $1.3 million for 2002, $0.9 million for 2001 and $0.6 million for 2000.

(14) 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:

	2002		
	Pre-tax Amount	Tax Benefit	Net-of-tax Amount
		(in thousands)	
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 loss	$ (26,898)	$9,448	$ (17,450)

	2001		
	Pre-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
		(in thousands)	
Unrealized gain on securities during the year	$ 1,775	$ (337)	$ 1,438
Net change in fair value of derivatives designated as cash flow hedges (net of minority interest share of $2,875)	(7,299)	2,932	(4,367)
Other comprehensive loss	$ (5,524)	$ 2,595	$ (2,929)

Items of other comprehensive income (loss) were not significant in 2000.

(15) INCOME TAXES

Income tax expense for the years indicated was:

	2002	2001	2000
		(in thousands)	
Current:			
Federal	$ (2,177)	$ 38,372	$ 27,122
State	(1,232)	1,986	1,283
	(3,409)	40,358	28,405
Deferred	33,487	10,224	2,576
Tax credits	(416)	(432)	(639)
	$ 29,662	$ 50,150	$ 30,342

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

Years ended December 31,	2002	2001
	(in thousands)	
Deferred tax assets, current:		
Valuation reserves	$ 1,655	$ 3,057
Mining development and oil exploration	1,008	--
Employee benefits	4,151	4,169
Items of other comprehensive income	7,560	613
Other	1,700	1,789
	16,074	9,628
Deferred tax liabilities, current:		
Prepaid expenses	1,031	--
State income taxes	6,002	94
Derivative fair value adjustments	723	1,776
Employee benefits	2,226	2,152
Items of other comprehensive income	--	1,946
Other	75	26
	10,057	5,994
Net deferred tax asset, current	$ 6,017	$ 3,634
Deferred tax assets, non-current:		
Accelerated depreciation, amortization and other plant-related differences	$ 6,779	$ 647
Mining development and oil exploration	196	697
Regulatory asset	1,866	2,168
Deferred revenue	937	804
Items of other comprehensive income	4,820	3,927
Net operating loss	1,490	2,198
Other	5,190	2,527
	21,278	12,968
Deferred tax liabilities, non-current:		
Accelerated depreciation, amortization and other plant-related differences	125,376	74,449
Regulatory liability	4,350	1,425
Mining development and oil exploration	11,594	8,650
Derivative fair value adjustments	1,317	--
Other	10,911	7,380
	153,548	91,904
Net deferred tax liability, non-current	$132,270	$78,936
Net Deferred Tax Liability	$126,253	$75,302

The following table reconciles the change in the net deferred income tax liability from December 31, 2001, to December 31, 2002, to deferred income tax expense:

	2002
	(in thousands)
Net change in deferred income tax liability from the preceding table	$ 50,951
Deferred taxes associated with 2001 Federal Income Tax Return True-up related to accelerated depreciation and other plant-related differences	(26,935)
Deferred taxes associated with other comprehensive loss	9,448
Other	(393)
Deferred income tax expense for the period	$ 33,071

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

	2002	2001	2000
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	0.7	1.4	1.5
Amortization of excess deferred and investment			

tax credits	(0.6)	(0.3)	(0.8)
Percentage depletion in excess of cost	(0.7)	(0.8)	(1.1)
Research and development credit	(1.5)	--	--
Other	(1.0)	1.1	1.9
	31.9%	36.4%	36.5%

At December 31, 2002 the Company had net operating loss carryforwards of $2.8 million which expire in the year 2020 and $1.1 million which expire in the year 2022.

(16) 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, 2002, 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: Electric, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; Integrated 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; and Communications, which primarily markets communications and software development services.

December 31:	2002	2001
	(in thousands)	
Total assets		
Integrated energy:		
Coal mining	$ 42,626	$ 42,994
Oil and gas	100,479	57,069
Energy marketing	267,125	133,358
Power generation	1,037,540	868,829
Electric utility	448,173	423,507
Communications	131,327	123,841
Corporate	7,899	2,713
Discontinued operations	--	10,090
Total assets	$ 2,035,169	$ 1,662,401
Capital expenditures and acquisitions		
Integrated energy:		
Coal mining	$ 3,635	$ 7,855
Oil and gas	50,838	27,114
Energy marketing	18,734	152
Power generation	176,476	497,653
Electric utility	31,251	41,313
Communications	21,607	20,030
Corporate	1,377	25
Total capital expenditures and acquisitions	$ 303,918	$ 594,142
Property, plant and equipment		
Integrated energy:		
Coal mining	$ 67,227	$ 63,592
Oil and gas	121,949	104,926
Energy marketing	27,016	660
Power generation	918,114	696,345
Electric utility	603,202	569,368
Communications	151,356	129,748
Corporate	1,402	25
Total property, plant and equipment	$ 1,890,266	$ 1,564,664

December 31:	2002	2001	2000
		(in thousands)	
External operating revenues			
Integrated energy:			
Coal mining	$ 20,825	$ 20,551	$ 20,880
Oil and gas	26,486	33,408	20,328
Energy marketing(a)	37,704	83,884	40,204
Power generation	133,517	80,233	20,083
Electric utility	162,186	212,355	173,308
Communications	32,677	20,258	7,689

Total external operating revenues	$ 413,395	$ 450,689	$ 282,492

(a) Operating revenues presented for energy marketing represent trading margins.

Intersegment operating revenues			
Integrated energy:			
Coal mining	$ 10,524	$ 11,249	$ 9,650
Total intersegment operating revenues(b)	$ 10,524	$ 11,249	$ 9,650

(b) In accordance with the provisions of SFAS 71, intercompany fuel sales are not eliminated.

Depreciation, depletion and amortization			
Integrated energy:			
Coal mining	$ 3,358	$ 2,984	$ 3,525
Oil and gas	7,799	7,806	4,071
Energy marketing	932	484	404
Power generation	27,325	16,520	3,646
Electric utility	17,499	15,773	14,966
Communications	12,678	9,944	6,012
Corporate	147	300	--
Total depreciation, depletion and amortization	$ 69,738	$ 53,811	$ 32,624
Operating income (loss)			
Integrated energy:			
Coal mining	$ 9,092	$ 6,586	$ 8,795
Oil and gas	6,471	15,193	7,906
Energy marketing	18,065	53,662	24,113
Power generation	55,363	27,455	20,374
Electric utility	58,160	84,108	68,208
Communications	(7,447)	(13,250)	(12,486)
Corporate	(7,103)	(3,984)	(1,821)
Total operating income	$ 132,601	$ 169,770	$ 115,089

December 31:	2002	2001	2000
		(in thousands)	
Interest income			
Integrated energy:			
Coal mining	$ 3,460	$ 8,125	$ 9,974
Oil and gas	2	45	39
Energy marketing	1,634	1,854	527
Power generation	22,273	8,991	4,085
Electric utility	734	4,858	5,658
Communications	3	15	657
Corporate	16,680	7,379	369
Intersegment eliminations	(44,157)	(28,895)	(14,242)
Total interest income	$ 629	$ 2,372	$ 7,067
Interest expense			
Integrated energy:			
Coal mining	$ 2,453	$ 5,752	$ 8,006
Oil and gas	59	145	372
Energy marketing	564	17	329
Power generation	49,124	33,593	11,911
Electric utility	13,663	15,780	17,411
Communications	3,993	5,789	6,244
Corporate	15,535	7,298	105
Intersegment eliminations	(44,157)	(28,895)	(14,242)
Total interest expense	$ 41,234	$ 39,479	$ 30,136
Income taxes			
Integrated energy:			
Coal mining	$ 3,220	$ 6,266	$ 2,660
Oil and gas	1,739	4,930	2,609
Energy marketing	6,396	20,933	9,308
Power generation	10,185	1,668	3,154

Electric utility	15,067	24,255	19,469
Communications	(3,948)	(6,561)	(6,477)
Corporate	(2,997)	(1,341)	(381)
Total income taxes	$ 29,662	$ 50,150	$ 30,342
Income (loss) from continuing operations			
Integrated energy:			
Coal mining	$ 8,572	$ 11,591	$ 7,172
Oil and gas	4,783	10,197	4,992
Energy marketing	12,739	34,566	13,973
Power generation	17,137	1,576	3,242
Electric utility	30,217	45,238	37,178
Communications	(7,260)	(12,300)	(11,382)
Corporate	(2,981)	(2,560)	(1,175)
Intersegment eliminations	(14)	(724)	(1,188)
Total income from continuing operations	$ 63,193	$ 87,584	$ 52,812

(17) ACQUISITIONS

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. The Millennium system is presently operating near capacity through shipper agreements. 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 give the Company a 100 percent ownership interest in Harbor and Pepperell.

The Company’s investments in the above 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 intangible assets by approximately $9.3 million, and were recorded as long-lived intangible assets.

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

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 and was funded through borrowings under short-term credit facilities.

On April 11, 2001, the Company’s power generation subsidiary, Black Hills Energy Capital, purchased the Fountain Valley facility, a 240 megawatt generation facility located near Colorado Springs, Colorado, featuring six LM-6000 simple-cycle, gas-fired turbines. The facility came on-line mid third quarter of 2001. The facility was purchased from Enron Corporation. Total cost of the project was approximately $183 million and has been financed primarily with non-recourse project debt. The Company has obtained an 11-year contract with Public Service Company of Colorado to utilize the facility for peaking purposes. The contract is a tolling arrangement in which the Company assumes no fuel price risk. The transaction has been accounted for as an asset purchase recorded at cost.

On August 31, 2001, Black Hills Energy Capital purchased a 277 megawatt gas-fired co-generation power plant project located in North Las Vegas, Nevada from Enron North America, a wholly owned subsidiary of Enron Corporation. At acquisition, the facility had a 53 megawatt co-generation power plant in operation, of which we own 50 percent. Most of the power from that facility is under a long-term contract expiring in 2024. Although we only own 50 percent of this plant, under generally accepted accounting principles the Company is required to consolidate 100 percent of this plant. The project also has a 224 megawatt combined-cycle expansion under construction of which we own 100 percent. The facility became fully operational in January 2003 and utilizes LM-6000 technology. The power to be generated by the expansion project is also under a long-term sales contract that expires in 2017. This contract for the expansion requires the purchaser to provide fuel to the power plant when it is dispatched. Total cost for the entire facility is expected to be approximately $325 million of which $314 million was expended as of December 31, 2002.

The acquisition has been accounted for under the purchase method of accounting and, accordingly, the purchase price of approximately $205 million has been allocated to the acquired assets and liabilities based on the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. Fair values in the allocation include assets acquired of approximately $150 million (excluding goodwill and other intangibles) and liabilities assumed of approximately $2.0 million. The purchase price and related acquisition costs exceeded the fair values assigned to net tangible assets by approximately $42.0 million, which was recorded as long-lived intangible assets.

In addition, during 2001, the Company acquired an additional 31 percent interest and a 13 percent interest in its consolidated majority-owned subsidiaries, Indeck North American Power Fund, L.P. and Indeck North American Power Partners, L.P., respectively, from minority shareholders. Total consideration paid was $15.9

million.

Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not significant to the Company's financial position or results of operations.

(18) DISCONTINUED OPERATIONS

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. The Company recorded an after-tax charge of approximately $1.0 million, which represents the difference between the carrying value of the assets and liabilities of the subsidiary versus its fair value, less cost to sell. The disposition was accounted for under the provisions of SFAS 144. Accordingly, results of operations and the related charges have been classified as "Discontinued operations" in the accompanying Consolidated Statements of Income, and prior periods have been restated. For business segment reporting purposes, the coal marketing business results were previously included in the energy marketing segment.

Revenues and net income from the discontinued operations are as follows:

	2002	2001	2000
		(in thousands)	
Gross margins on energy trading contracts	$ 235	$ 3,660	$ 1,578
Pre-tax income (loss) from discontinued operations	(2,679)	886	52
Pre-tax loss on disposal	(1,588)	--	--
Income tax benefit (expense)	1,630	(393)	(16)
Net (loss) income from discontinued operations	$ (2,637)	$ 493	$ 36

Assets and liabilities of the discontinued operations are as follows:

	2002	2001
	(in thousands)	
Current assets	$ --	$ 7,878
Non-current assets	--	2,212
Current liabilities	--	(8,724)
Non-current liabilities	--	(96)
Net assets (liabilities) of discontinued operations	$ --	$ 1,270

(19) OIL AND GAS RESERVES (Unaudited)

Black Hills Exploration and Production has interests in 824 producing oil and gas properties in nine states. Black Hills Exploration and Production also holds leases on approximately 190,803 net undeveloped acres.

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, 2002, 2001 and 2000, 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.

	2002		2001		2000	
	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	4,055	24,071	4,413	18,404	4,109	19,460
Production	(455)	(4,707)	(446)	(4,615)	(352)	(3,285)
Additions	188	8,504	749	19,111	625	4,228
Property sales	(11)	--	--	--	--	--
Revisions to previous estimates	1,103	645	(661)	(8,829)	31	(1,999)
Balance at end of year	4,880	28,513	4,055	24,071	4,413	18,404
Proved developed reserves at end of year included above	4,188	27,473	2,962	22,420	3,047	16,418
Year-end prices (average well-head)	$29.24	$ 3.41	$18.12	$ 2.05	$26.76	$ 8.05

(20) 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 2002 and 2001.

2002

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts and common stock prices)			
2002				
Operating revenues	$ 95,768	$ 105,364	$ 112,641	$ 110,146
Operating income	32,039	32,894	35,444	32,224
Income from continuing operations	14,895	14,719	17,449	16,130
Loss from discontinued operations	(1,725)	(912)	--	--
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	0.54	0.55	0.65	0.60
Discontinued operations	(0.05)	(0.04)	--	--
Change in accounting principle	0.03	--	--	--
Total	0.52	0.51	0.65	0.60
Diluted -				
Continuing operations	0.55	0.54	0.64	0.59
Discontinued operations	(0.06)	(0.03)	--	--
Change in accounting principle	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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts and common stock prices)			
	2001			
Operating revenues	$ 142,301	$ 130,442	$ 95,124	$ 94,071
Operating income	60,711	63,651	30,817	14,591
Income from continuing operations	31,436	34,528	17,005	4,615
Income (loss) from discontinued operations	655	325	(638)	151
Net income	32,091	34,853	16,367	4,766
Net income available for common stock	32,050	34,553	16,235	4,712
Earnings per common share:				
Basic -				
Continuing operations	1.36	1.34	0.64	0.17
Discontinued operations	0.03	0.01	(0.03)	0.01
Total	1.39	1.35	0.61	0.18
Diluted -				
Continuing operations	1.34	1.33	0.63	0.17
Discontinued operations	0.03	0.01	(0.02)	0.01
Total	1.37	1.34	0.61	0.18
Dividends paid per share	0.28	0.28	0.28	0.28
Common stock prices				
High	45.74	58.50	45.55	34.20
Low	31.00	39.50	27.76	26.00

(21) SUBSEQUENT EVENTS

Registration Statement

On November 27, 2002, we filed a Form S-3 Registration Statement with the Securities and Exchange Commission so that we may proceed with equity or debt offerings at unspecified future dates. This "shelf registration" became effective on February 5, 2003 and will enable us to attain up to $400 million in additional capital as opportunities warrant.

Acquisition

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 $53 million, which includes $30.5 million for the October 2002 acquisition of Mallon's debt to Aquila Energy Capital Corporation and the settlement of outstanding hedges. Mallon shareholders received 0.044 of a share of the Company's common stock for each share of Mallon, which was equivalent to approximately 482,000 shares of Black Hills Corporation common stock. The purchase will be accounted for under the purchase method of accounting and, accordingly, the purchase price will be 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 will be subject to adjustment, generally within one year of the acquisition date. The Company will include this acquisition in its consolidated financial statements beginning on the date of acquisition.

Unaudited

Mallon's proved reserves, as reported at December 31, 2001, were 53.3 billion cubic feet of gas equivalent. 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.

Current daily net production of the Mallon properties is nearly 12 million cubic feet of gas equivalent. Mallon operates 152 of 174 total gas and oil wells, with working interests averaging 90 to 100 percent in most of the wells and undeveloped acreage.

The Company expects the acquisition to increase the Company's gas and oil production immediately by approximately 50 percent and more than double our proven oil and gas reserves.

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

In May 2002, Black Hills Corporation announced that the Board of Directors, upon recommendation of its Audit Committee, ended the engagement of Arthur Andersen LLP as the Company's independent public accountants and in June 2002 engaged Deloitte & Touche LLP to serve as the Company's independent auditors for the fiscal year ended December 31, 2002.

For more information, see the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2002.

On November 15, 2002, Deloitte & Touche LLP completed re-audits of the Company's 1999, 2000 and 2001 consolidated financial statements, which were previously audited by Arthur Andersen LLP. For additional information, see the Company's Current Report on Form 8-K dated November 25, 2002.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information regarding our directors and information required by Item 405 of Regulation S-K are incorporated herein by reference to the Proxy Statement for the Annual Shareholders' Meeting to be held May 28, 2003.

EXECUTIVE OFFICERS

Daniel P. Landguth, age 56, was elected Chairman of the Board and Chief Executive Officer in January 1991. 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.

Everett E. Hoyt, age 63, has been President and Chief Operating Officer since February 2001. Since 1989, he has been President and Chief Operating Officer of our electric utility business – a role he continues to play. 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 51, has been the President and Chief Operating Officer of our Integrated Energy Group since November 2001. He served as Senior Vice President-Power Supply and Power Marketing since January 30, 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 39, has been our Senior 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.

Ronald D. Schaible, age 58, has been Senior Vice President of Communications of Black Hills Corporation and Vice President and General Manager of Black Hills FiberCom since October 1998. Mr. Schaible has more than 25 years experience in the telecommunications industry. From 1995 to 1998, he was Vice President and General Manager of the Kansas City and Missouri subsidiaries of Brooks Fiber Properties. Mr. Schaible was responsible for both network construction and operations in Kansas City. He holds a B.S. in Electrical Engineering from South Dakota State University.

James M. Mattern, age 48, has been the Senior Vice President-Corporate Administration since September 1999, 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 15 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 46, has been our General Counsel and Corporate Secretary since January 2001. 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.

Richard T. Ashbeck, age 44, has been Vice President and Treasurer since March 2002. From July 2000 to March 2002, he was Vice President – Finance and Fund Management for Black Hills Energy Capital, Inc. Prior to joining Black Hills, Mr. Ashbeck was Chief Financial Officer of Indeck Capital, Inc., a company engaged in the acquisition, development, ownership and operation of power generation facilities, from July 1998 until July 2000, and was a banker with Fuji Bank from July 1988 to July 1998. He holds a B.S.C. in Accounting and an M.B.A. from DePaul University.

Roxann R. Basham, age 41, has been our Vice President-Controller since March 2000. 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 19 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.

Russell L. Cohen, age 42, has been Vice President – Risk Management since May 2002. Prior to joining Black Hills, Mr. Cohen was General Partner and Chief Financial Officer at Regenests 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.

David R. Emery, age 40, has been our Vice President-Fuel Resources since January 1997. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 14 years of experience with us. He holds a B.S. in Petroleum Engineering from the University of Wyoming and an M.S. in Business Administration from the University of South Dakota.

Kyle D. White, age 43, has been Vice President – Corporate Affairs since January 30, 2001 and Vice President-Marketing and Regulatory Affairs since July 1998. Mr. White served as Director-Strategic Marketing and Sales from 1993 to January 1998 and Vice President-Energy Services from January 1998 to July 1998. He has a total of 20 years of experience with us. Mr. White holds a B.S. and M.S. in Business Administration from the University of South Dakota.

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 28, 2003.

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 28, 2003.

The following table includes information as of December 31, 2002 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)	1,082,253	$ 27.21	968,413(2)
Equity compensation plans not approved by security holders(3)	28,745(4)	26.52	144,666(5)
Total	1,110,998	$ 27.19	1,113,079

(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, 2002, the Employee Stock Purchase Plan had 24,789 shares subscribed to (which are reflected in column (a)) at a price of $23.45 per share and 135,523 shares available for future issuance (which are reflected in column (c)).

(2) 135,523 shares are available for future issuance under the Employee Stock Purchase Plan, 2,222 shares are available for issuance under the 1996 and 1999 Stock Option Plans and 830,668 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 202,472 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.

(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 the Company 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 the well-being of the Company and its shareholders and to further align the long-term interests of the outside directors with those of the shareholders by 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 the employ of the Company and its subsidiaries persons of experience and ability by providing additional incentive to those who contribute significantly to the successful and profitable operation of the business and affairs of the 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 common stock of the Company. 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 the Company’s 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 28, 2003.

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

Within 90 days prior to the filing date of the Form 10-K, our chief executive officer and chief financial officer evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-14(c) and 15d-14(c) of the Securities Exchange Act of 1934 (Exchange Act). 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 included in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the required time periods.

Changes in internal controls

Our chief executive officer and chief financial officer have concluded that there were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their most recent evaluation of such controls, and that there were no significant deficiencies or material weaknesses in our internal controls.

PART IV

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, 2002, 2001 and 2000.

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, 2002, 2001 AND 2000

		Additions			
Description	**Balance at beginning of year**	**Charged to costs and expenses**	**Other (a)**	**Deductions (b)**	**Balance at end of year**
			(In thousands)		
Allowance for doubtful accounts:					
2002	$ 5,793	$ 791	$ (823)	$ (1,901)	$ 3,860
2001	3,510	3,266	(44)	(939)	5,793
2000	278	3,370	--	(138)	3,510

(a) Recoveries

(b) Uncollectible accounts written off

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3. Exhibits

Exhibit Number	Description
2*	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)).
3.1*	Articles of Incorporation of the Registrant (filed as an exhibit to the Registrant's Registration Statement on Form S-4 (No. 333-52664)).
3.2*	Articles of Amendment of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
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3.4*	Statement of Designations, Preferences and Relative Rights and Limitations of No Par Preferred Stock, Series 2000-A of the Registrant (filed as an exhibit to the Registrant's Form 8-K filed on December 26, 2000).
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10.5*	Second Restated and Amended Power Sales Agreement dated September 29, 1997, between PacifiCorp and Black Hills Power, Inc. (filed as Exhibit 10(e) to the Registrant's Form 10-K for 1997).
10.6*	Coal Supply Agreement for Wyodak Unit #2 dated February 3, 1983, and Ancillary Agreement dated February 3, 1982, between Wyodak Resources Development Corp., Pacific Power & Light Company and Black Hills Power, Inc. (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1983). Amendment to Agreement for Coal Supply for Wyodak #2 dated May 5, 1987 (filed as Exhibit 10(o) to the Registrant's Form 10-K for 1987).
10.7*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between Wyodak Resources Development Corp. and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
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10.10+	First Amendment to Pension Equalization Plan.
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10.16*+	Form of Change in Control Agreements for Richard Ashbeck, Roxann Basham, David Emery, Steven Helmers, James Mattern, Thomas M. Ohlmacher, Mark Thies and Kyle White (filed as Exhibit 10(af) to the Registrant's Form 10-K for 1995).
10.17*+	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1997).
10.18*+	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1999).
10.19*+	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Daniel P. Landguth as employee (filed as Exhibit 10.1 to the Registrant's Form 8-K for December 20, 2002).
10.20*+	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Everett E. Hoyt, as employee (filed as Exhibit 10.2 to the Registrant's Form 8-K for December 20, 2002).
10.21*	Agreement and Plan of Merger, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 2 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.22*	Addendum to the Agreement and Plan of Merger, dated as of April 6, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 3 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.23*	Supplemental Agreement Regarding Contingent Merger Consideration, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 4 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).

10.24*	Supplemental Agreement Regarding Restructuring of Certain Qualifying Facilities (Exhibit 5 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.25*	Addendum to the Agreement and Plan of Merger, dated as of June 30, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 6 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.26*	Registration Rights Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 7 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.27*	Shareholders Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 8 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.28*	Agreement and Plan of Merger among Black Hills Corporation, Black Hills Acquisition Corp. and Mallon Resources Corporation, dated as of October 1, 2002 (filed as Annex A to the Proxy Statement/Prospectus included in the Registration Statement on Form S-4 No. 333-101576).
10.29*	Amended and Restated Credit Agreement Between Mallon Resources Corporation and Mallon Oil Company and Black Hills Corporation dated as of October 1, 2002 (filed as Exhibit 99.2 to the Registrant's Form 8-K for October 1, 2002).
10.30*	Amended and Restated Advancing Note dated October 1, 2002, Between Mallon Resources Corporation and Mallon Oil Company and Black Hills Corporation (filed as Exhibit 99.3 to the Registrant's Form 8-K for October 1, 2002).
10.31*	Assignment of Credit Agreement, Note, Liens and Security Documents dated as of October 1, 2002, Between Aquilla Energy Capital Corporation, Black Hills Corporation (filed as Exhibit 99.4 to the Registrant's Form 8-K for October 1, 2002).
10.32*	3-year Credit Agreement dated as of August 28, 2001 among Black Hills Corporation, as Borrower, The Financial Institutions party, hereto, as Banks, ABN AMRO BANK N.V., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent, Bank of Montreal, 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, 2001). First and Second Amendment to 3-year Credit Agreement (filed as Exhibits 10.4 and 10.5 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2002).
10.33*	$195 Million Amended and Restated 364-day Credit Agreement dated as of August 27, 2002 among Black Hills Corporation, as Borrower, The Financial Institutions party, hereto, as Banks, ABN AMRO BANK N.A., as Syndication Agent, Bank of Montreal, 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, 2002).
10.34*	$35 Million Term Credit Agreement dated as of September 25, 2002, among Black Hills Corporation (Borrower), The Financial Institutions Party Hereto (Banks) and Credit Lyonnais New York Branch (Administrative Agent) (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended September 30, 2002).
10.35*	Purchase and Sale Agreement by and between TLS Investors, LLC and Black Hills Energy Capital, Inc. dated June 18, 2001 to purchase Southwest Power, LLC (filed as Exhibit 10.30 to the Registrant's Form 10-K for 2001).
10.36*	Agreement for Lease between Wygen Funding, Limited Partnership and Black Hills Generation, Inc. dated as of July 20, 2001 (filed as Exhibit 10.31 to the Registrant's Form 10-K for 2001).
10.37*	Amendment No. 1 dated as of December 20, 2001 to Agreement for Lease dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Owner and Black Hills Generation, Inc., as Agent (filed as Exhibit 10.32 to the Registrant's Form 10-K for 2001).
10.38*	Lease Agreement dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Lessor and Black Hills Generation, Inc. as Lessee (filed as Exhibit 10.33 to the Registrant's Form 10-K for 2001).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors' Consent.
23.2	Consent of Petroleum Engineer and Geologist.
99.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Previously filed as part of the filing indicated and incorporated by reference herein.

+ Indicates a board of director or management compensatory plan.

(b) Reports on Form 8-K

We have filed the following Reports on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2002:

Form 8-K for October 1, 2002.

Reported under Item 5 that Black Hills Corporation and Mallon Resources Corporation entered into a definitive merger agreement for the acquisition of Mallon Resources in a stock-for-stock transaction.

Form 8-K for November 25, 2002.

Reported and filed under Item 5 Black Hills Corporation's Re-audited Financial Statements for 2001, 2000 and 1999.

Form 8-K for November 27, 2002.

Reported under Item 5 the amendment and extension of a $50 million secured financing for the expansion of the Las Vegas II project.

Form 8-K for December 20, 2002.

Reported under Item 5 that Black Hills Corporation entered into employment agreements with Daniel P. Landguth, Chief Executive Officer and Everett E. Hoyt, President and Chief Operating Officer.

(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/ DANIEL P. LANDGUTH
Daniel P. Landguth, Chairman
and Chief Executive Officer

Dated: March 27, 2003

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/ DANIEL P. LANDGUTH Daniel P. Landguth, Chairman, and Chief Executive Officer	Director and Principal Executive Officer	March 27, 2003
/S/ MARK T. THIES Mark T. Thies, Senior Vice President and Chief Financial Officer	Principal Financial Officer	March 27, 2003
/S/ ROXANN R. BASHAM Roxann R. Basham, Vice President-Controller, and Assistant Secretary	Principal Accounting Officer	March 27, 2003
/S/ BRUCE B. BRUNDAGE Bruce B. Brundage	Director	March 27, 2003
/S/ DAVID C. EBERTZ David C. Ebertz	Director	March 27, 2003
/S/ JOHN R. HOWARD John R. Howard	Director	March 27, 2003
/S/ EVERETT E. HOYT Everett E. Hoyt, President and Chief Operating Officer	Director and Officer	March 27, 2003
/S/ KAY S. JORGENSEN Kay S. Jorgensen	Director	March 27, 2003
/S/ DAVID S. MANEY David S. Maney	Director	March 27, 2003
/S/ THOMAS J. ZELLER Thomas J. Zeller	Director	March 27, 2003

CERTIFICATION

I, Daniel P. Landguth, certify that:

1. I have reviewed this annual report on Form 10-K of Black Hills Corporation;

2. Based on my knowledge, this annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures 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 annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ Daniel P. Landguth

Chairman and
Chief Executive Officer

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 annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a. designed such disclosure controls and procedures 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 annual report is being prepared;

b. evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ Mark T. Thies

Senior Vice President and
Chief Financial Officer

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10.16*+	Form of Change in Control Agreements for Richard Ashbeck, Roxann Basham, David Emery, Steven Helmers, James Mattern, Thomas M. Ohlmacher, Mark Thies and Kyle White (filed as Exhibit 10(af) to the Registrant's Form 10-K for 1995).
10.17*+	Outside Directors Stock Based Compensation Plan (filed as Exhibit 10(t) to the Registrant's Form 10-K for 1997).
10.18*+	Officers Short-Term Incentive Plan (filed as Exhibit 10(s) to the Registrant's Form 10-K for 1999).
10.19*+	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Daniel P. Landguth as employee (filed as Exhibit 10.1 to the Registrant's Form 8-K for December 20, 2002).
10.20*+	Employment Agreement dated December 20, 2002, by and between Black Hills Corporation, as employer, and Everett E. Hoyt, as employee (filed as Exhibit 10.2 to the Registrant's Form 8-K for December 20, 2002).
10.21*	Agreement and Plan of Merger, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 2 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.22*	Addendum to the Agreement and Plan of Merger, dated as of April 6, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 3 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.23*	Supplemental Agreement Regarding Contingent Merger Consideration, dated as of January 1, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S.

	Forsythe and John W. Salyer, Jr. (Exhibit 4 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.24*	Supplemental Agreement Regarding Restructuring of Certain Qualifying Facilities (Exhibit 5 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.25*	Addendum to the Agreement and Plan of Merger, dated as of June 30, 2000, among Black Hills Corporation, Black Hills Energy Capital, Inc., Indeck Capital, Inc., Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 6 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.26*	Registration Rights Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 7 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.27*	Shareholders Agreement among Black Hills Corporation, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. (Exhibit 8 to Schedule 13D filed on behalf of the former shareholders of Indeck Capital, Inc. consisting of Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr., dated July 7, 2000).
10.28*	Agreement and Plan of Merger among Black Hills Corporation, Black Hills Acquisition Corp. and Mallon Resources Corporation, dated as of October 1, 2002 (filed as Annex A to the Proxy Statement/Prospectus included in the Registration Statement on Form S-4 No. 333-101576).
10.29*	Amended and Restated Credit Agreement Between Mallon Resources Corporation and Mallon Oil Company and Black Hills Corporation dated as of October 1, 2002 (filed as Exhibit 99.2 to the Registrant's Form 8-K for October 1, 2002).
10.30*	Amended and Restated Advancing Note dated October 1, 2002 Between Mallon Resources Corporation and Mallon Oil Company and Black Hills Corporation (filed as Exhibit 99.3 to the Registrant's Form 8-K for October 1, 2002).
10.31*	Assignment of Credit Agreement, Note, Liens and Security Documents dated as of October 1, 2002, Between Aquilla Energy Capital Corporation, Black Hills Corporation (filed as Exhibit 99.4 to the Registrant's Form 8-K for October 1, 2002).
10.32*	3-year Credit Agreement dated as of August 28, 2001 among Black Hills Corporation, as Borrower, The Financial Institutions party, hereto, as Banks, ABN AMRO BANK N.V., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent, Bank of Montreal, 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, 2001). First and Second Amendment to 3-year Credit Agreement (filed as Exhibits 10.4 and 10.5 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2002).
10.33*	$195 Million Amended and Restated 364-Day Credit Agreement dated as of August 27, 2002 among Black Hills Corporation, as Borrower, The Financial Institutions party, hereto, as Banks, ABN AMRO BANK N.A., as Syndication Agent, Bank of Montreal, 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, 2002).
10.34*	$35 Million Term Credit Agreement dated as of September 25, 2002, among Black Hills Corporation (Borrower), The Financial Institutions Party Hereto (Banks) and Credit Lyonnais New York Branch (Administrative Agent) (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended September 30, 2002).
10.35*	Purchase and Sale Agreement by and between TLS Investors, LLC and Black Hills Energy Capital, Inc. dated June 18, 2001 to purchase Southwest Power, LLC (filed as Exhibit 10.30 to the Registrant's Form 10-K for 2001).
10.36*	Agreement for Lease between Wygen Funding, Limited Partnership and Black Hills Generation, Inc. dated as of July 20, 2001 (filed as Exhibit 10.31 to the Registrant's Form 10-K for 2001).
10.37*	Amendment No. 1 dated as of December 20, 2001 to Agreement for Lease dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Owner and Black Hills Generation, Inc., as Agent (filed as Exhibit 10.32 to the Registrant's Form 10-K for 2001).
10. 38*	Lease Agreement dated as of July 20, 2001 between Wygen Funding, Limited Partnership as Lessor and Black Hills Generation, Inc. as Lessee (filed as Exhibit 10.33 to the Registrant's Form 10-K for 2001).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Independent Auditors' Consent.
23.2	Consent of Petroleum Engineer and Geologist.
99.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.2	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.

Exhibit 3.3

BLACK HILLS CORPORATION

AMENDED AND RESTATED BYLAWS

ARTICLE I

MEETINGS OF SHAREHOLDERS

Section 1. Place. Meetings of the shareholders shall be held at such place within or without the State of South Dakota as the Board of Directors may from time to time determine and as stated in the notice of the meeting.

Section 2. Annual Meeting. The annual meeting of the shareholders shall be held at such time within six months after the end of each fiscal year of the Company as the Board of Directors designates for the purpose of electing directors and for the transacting of any other business as may be brought before the meeting.

Section 3. Special Meetings. All annual and special meetings of the shareholders shall be called by a majority of the Board of Directors.

Section 4. Notice. Unless all shareholders entitled to vote at the meeting waive notice in writing, written notice stating the place, day and hour of each meeting of shareholders, and in the case of a special meeting, further stating the purpose for which such meeting is called, shall be mailed at least ten days before the meeting when called by the Board of Directors to each stockholder of record who shall be entitled to vote thereat to the last known post office address of each such stockholder as it appears upon the stock transfer books of the Company. However, notice of a meeting, at which proposal to increase the capital stock or indebtedness is to be considered, shall be given at least sixty days prior to such meeting.

Section 5. Quorum. The holders of a majority of the issued and outstanding shares of the capital stock of the Company entitled to vote thereat, present in person or represented by proxy, shall constitute a quorum for the transaction of business at all meetings of the shareholders except as may otherwise be provided by law or by the Articles of Incorporation. If a quorum or greater number as may be required by law or the Articles shall not be present or represented at any meeting of the shareholders, a majority of the shareholders who are present in person or by proxy and who are entitled to vote thereat shall have the power to adjourn the meeting from time to time without notice other than announcement at the meeting until such quorum or such greater number shall have been obtained.

Section 6. Adjourned Meeting. The majority of the shareholders who are entitled to vote and who are present in person or by proxy at any regular or special meeting of the shareholders shall have the right to adjourn the meeting from time to time without notice other than announcement at the meeting to be adjourned; provided, however, the meeting may not be adjourned for a period longer than sixty days from the date of the meeting as set forth in the notice thereof.

Section 7. Voting. At each meeting of the shareholders, every stockholder having the right to vote shall be entitled to vote one vote per share in person or by proxy appointed by an instrument in writing subscribed by such stockholder. No proxy shall be valid after eleven months from the date of its execution, unless otherwise provided in the proxy. All voting for directors shall be by written ballot. All elections shall be had and all questions decided by a plurality except as otherwise provided by law or by the Articles of Incorporation.

Section 8. Inspectors. The Board of Directors or, if the Board shall not have made the appointment, the person presiding at any meeting of shareholders shall have power to appoint one or more persons, other than the nominees for directors, to act as inspectors to receive, canvass and report the votes cast by the shareholders at such meeting. Any inspector so appointed who for any reason does not serve in such capacity may be replaced by the person presiding at the meeting.

ARTICLE II

BOARD OF DIRECTORS

Section 1. Definitions. For the purposes of these Bylaws an “Inside Director” is a director who is an employee of the Company, an officer of the Company, a person who has in the past served as an officer of the Company or any person whose relationship to the Company other than as a director gives him access on a regular basis to material information about the Company that is not generally available. Any director who is not an Inside Director would for the purpose of these Bylaws constitute an “Outside Director.” For the purpose of this Section “Company” shall also include any subsidiary of the Company.

Section 2. Management of the Company. The property, business and affairs of the Company shall be managed by or under the direction of its Board of Directors.

Section 3. Qualifications of Directors. At the time a person is elected as director by the shareholders, that person must beneficially own at least 100 shares of the common stock of the Company; and if such person is elected by the shareholders, the person must be duly qualified to vote such stock at the said election. Each director is required to apply at least 50 percent of his or her retainer toward the purchase of additional shares until the director has accumulated at least 2,000 shares of common stock. No person shall be elected or stand for reelection as a director who will be seventy (70) years of age or older on the thirty-first day of December of the year of the election, except in the event the Board of Directors has not yet identified a director to be elected to replace any director who will be seventy (70) years of age during the year in which he or she stands for reelection, a director may stand for reelection solely for the purpose of filling the slate of directors. However, upon the Board of Directors’ choosing a replacement director, the incumbent director shall tender his or her resignation to the Chairman.

Section 4. Number and Election; Vacancies and Removal. The number of members of the Board of Directors shall not be less than nine (9); provided, the Board of Directors may change the number of directors through amendments to its Bylaws. The Board of Directors shall be and is divided into three classes, Class I, Class II and Class III, which shall be as nearly equal in number as possible. Each director shall serve for a term ending on the date of the third annual meeting following the annual meeting at which such director was elected; provided, each initial director in Class I shall hold office until the annual meeting of shareholders in 2002, each initial director in Class II shall hold office until the annual meeting of shareholders in 2003, and each initial director in Class III shall hold office until the annual meeting of shareholders in 2001.

The Board of Directors is expressly authorized to determine the rights, powers, duties, rules and procedures that affect the power of the Board of Directors to manage and direct the business and affairs of the Corporation, including the power to designate and empower committees of the Board of Directors, to elect, appoint and empower the officers and other agents of the Corporation, and to determine the time and place of, and the notice requirements for, Board meetings, as well as quorum and voting requirements for, and the manner of taking, Board action.

In the event of any change in the authorized number of directors, the Board of Directors shall apportion any newly created directorships to, or reduce the number of directorships in, such class or classes as shall, so far as possible, equalize the number of directors in each class. The Board of Directors shall allocate consistently with the rule that the three classes shall be as nearly equal in number of directors as possible, and appoint any newly-created directorship for a term of office continuing until the next election for the class to which such Director shall have been appointed.

Any vacancies in the Board of Directors for any reason, including any newly created directorships resulting from any increase in the number of directors, may be filled by the Board of Directors, acting by a majority of the directors then in office, although less than a quorum; and any directors so chosen shall hold office until the next election of the class for which such directors shall have been chosen.

Notwithstanding any of the foregoing, each director shall serve for a term continuing until the annual meeting of shareholders at which the term of the class to which he was elected expires and until his successor is elected and qualified or until his or her earlier death, resignation or removal; except, a director may be removed from office prior to the expiration of his or her term only for cause and by a vote of the majority of the total number of members of the Board of Directors without including the director who is the subject of the removal determination and without such director being entitled to vote thereon.

Section 5. Compensation. Outside Directors shall be entitled to such compensation and expenses as may be determined by resolution of the Board. Outside Directors may serve the Company in other capacities and receive compensation therefor.

Section 6. Meetings. The Board of Directors may hold meetings within or without the State of South Dakota. Members of the Board of Directors or any committee thereof may participate in a meeting of such Board or committee by means of a conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear each other at the same time, and participation by such means shall constitute presence in person at a meeting.

Section 7. Regular Meetings. The annual meeting of the Board of Directors for the election of officers and to conduct such other business to be brought before the meeting shall, if practicable, be held on the same day as and immediately after the annual election of the directors by the shareholders or any adjournment thereof, and no notice thereof need be given. Further regular meetings of the Board may be held with or without notice at such time and place as shall from time to time be determined by the Board by resolution.

Section 8. Special Meetings. Special meetings of the Board of Directors may be called either by the Chairman of the Board, the Chief Executive Officer, the President or by the Secretary upon the written request of any two directors by giving oral or written notice to each director stating the time and place of such meeting.

Section 9. Notice of Meetings. Notice shall be considered to have been given if a notice is either orally communicated to a director at least twelve hours prior to such meeting or placed in writing and mailed to the director at his last known post office address as shown by the records of the Company at least four days prior to the meeting. Any notice to be given a director for a meeting of the directors may be waived by the director in writing either before or after the meeting. Presence of any director at a meeting of the Board shall be considered to be a waiver of notice by such director unless such director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened. Neither the business to be transacted nor the purpose of any regular or special meeting of the Board of Directors need be specified in the notice or waiver of notice of such meeting.

Section 10. Quorum. At all meetings of the Board of Directors a majority of the number of directors at the time in office shall constitute a quorum for the transaction of business; provided, less than a quorum of directors may fill vacancies as set forth in Section 4 of this Article II. The act of a majority of the number of directors at the time in office shall be the act of the Board of Directors. If at any meeting of the board there shall be less than a quorum present, a majority of those present may adjourn the meeting from time to time until a quorum is obtained and no further notice thereof need be given other than by announcement at said meeting which shall be so adjourned.

Section 11. Manifestation of Dissent. A director of the Company who is present at a meeting of the Board of Directors at which action on any corporate matter is taken shall be presumed to have assented to the action taken unless his dissent shall be entered in the minutes of the meeting or unless he shall file his written dissent to such action with the person acting as the secretary of the meeting before the adjournment thereof or shall forward such dissent by registered mail to the Secretary of the Company immediately after the adjournment of the meeting. Such right to dissent shall not apply to a director who voted in favor of such action.

Section 12. Action Taken Without Meeting. Any action which may be taken at a meeting of the directors or of a committee may be taken without a meeting if a consent in writing setting forth the actions so to be taken shall be signed before such action by all of the directors, or all of the members of the committee, as the case may be. Such consent shall have the same effect as a unanimous vote.

ARTICLE III

COMMITTEES

Section 1. Executive Committee. The Board of Directors shall appoint from among its members an executive committee of at least five directors. The Chairman of the Board, the Chief Executive Officer or the President shall be a member of the executive committee. At least three members of the executive committee shall be Outside Directors. The executive committee (i) shall recommend to the Board persons to be elected as officers, (ii) may consider and make recommendations to the Board on other Board actions, and (iii) may perform such other duties as may be permitted by law.

Section 2. Audit Committee. The Board of Directors shall appoint at least three of its Outside Directors to serve as an audit committee, all of whom shall have no relationship to the Company that may interfere with the exercise of their independence from management. The audit committee shall meet prior to and after each yearly audit with representatives of the independent accounting firm approved by the shareholders for the purpose of reviewing the audit of such firm of the Company's financial condition and shall each year recommend to the Board an independent accounting firm to be appointed by the Board for the ratification by the shareholders and shall perform such other duties as assigned by the Board.

Section 3. Compensation Committee. The Board of Directors shall appoint at least three of its Outside Directors to serve as a compensation committee. The compensation committee (i) shall perform any function required by directors in the administration of all federal and state statutes relating to employment and compensation, (ii) shall recommend to the Board the compensation for officers, and (iii) shall consider and approve the compensation program, including the benefit program and stock ownership plans, of the Company.

Section 4. Governance Committee. The Board of Directors shall appoint a Governance Committee to be composed of a minimum of four Outside Directors as determined by the Board of Directors. An Outside Director shall be appointed by the Board of Directors to serve as Lead Director of the Governance Committee. The Governance Committee shall provide action and oversight on the following matters: (i) to recruit and nominate individuals to serve as Directors of the Company; (ii) to consider candidates to fill new positions created by expansion and vacancies that occur by resignation, retirement or for any other reason; (iii) to assess the size and other membership needs of the Board of Directors and establish selection criteria for Board Membership; (iv) to establish and regularly review guidelines for corporate governance; (v) to implement and administer an annual evaluation of the performance of the Board of Directors; (vi) to implement and administer the process for orienting new Directors both to the Company, and to their responsibilities as Board Members; (vii) to nominate on an annual basis an Outside Director to serve as Lead Director who will serve as Chairman of the Governance Committee; (viii) to regularly review the independence of Board Members; and (ix) to perform such other duties assigned by the Board.

Section 5. Other Committees. The Board of Directors may also appoint from among its own members such other committees as the Board may determine and assign such powers and duties as shall from time to time be prescribed by the Board.

Section 6. Removal from Committees and Rules of Procedure. Subject to these Bylaws directors may be removed from the committees and vacancies therein may be filled by a majority of the Board of Directors. A meeting of any committee may be called by any member of the committee. The provisions of these Bylaws concerning notice of meetings, compensation, manifestation of dissent and taking action without a meeting as they pertain to directors shall also pertain to committee meetings.

ARTICLE IV

OFFICERS

Section 1. Officers. The Board of Directors shall elect as officers of the Company a Chief Executive Officer, a President, a Vice President, a Secretary, and a Treasurer. If deemed desirable or expedient, the Board of Directors may elect a Chairman of the Board, a Controller, and such other Vice Presidents and officers as the Board may determine is necessary for the conduct of the business of the Company. Officers may also be directors. Any two or more offices may be held by the same person. No person shall hold an officer position after the last day of the month during which said person became sixty-five years of age.

Section 2. Term and Removal. All officers of the Company shall serve at the pleasure of the Board of Directors, and the Board at any regular or special meeting by the vote of a majority of the whole Board may remove an officer from an office.

Section 3. Duties of the Chairman of the Board and the Chief Executive Officer. The Chairman of the Board and the Chief Executive Officer may, but need not be the same person. The Chief Executive Officer shall be the chief administrative officer of the Company. The Chief Executive Officer (i) shall exercise such duties as customarily pertain to the office of Chief Executive Officer, (ii) shall have general and active management authority and supervision over the property, business and affairs of the company and over its officers and employees, (iii) may appoint employees, consultants and agents as deemed necessary for the proper conduct of the Company’s business, (iv) may sign, execute and deliver in the name of the Company powers of attorney, contracts, bonds and other obligations subject to direction of the Board as set forth in Article VII of these Bylaws, (v) shall recommend to the Board of Directors persons for appointment to offices and committees and for nomination of directors, and (vi) shall perform such other duties as may be prescribed from time to time by the Board of Directors. The Chairman of the Board, or in his/her absence, the Chief Executive Officer or other Board designee, shall preside at stockholder meetings and at meetings of the Board of Directors, and shall perform such other duties as may be prescribed from time to time by the Board of Directors.

Section 4. Duties of the President. The President shall perform such duties as may be prescribed from time to time by the Board of Directors, the Chairman of the Board or the Chief Executive Officer. The President, in the absence or disability of the Chief Executive Officer, shall perform the duties and exercise the powers of the Chief Executive Officer.

Section 5. Duties of Vice Presidents. The Vice Presidents shall have such powers and perform such duties as may be assigned to them by the Board of Directors, the Chairman of the Board, and the Chief Executive Officer. In the absence or disability of the Chairman of the Board, the Chief Executive Officer, and the President, the Vice Presidents in the order as designated by the Board, or if the Board so directs, by the Chairman of the Board and the Chief Executive Officer, shall perform the duties and exercise the powers of the Chairman of the Board and the Chief Executive Officer.

Section 6. Duties of Secretary. The Secretary shall attend all meetings of the Board and shareholders, record all votes and the minutes of all proceedings in books to be kept for such purposes and shall perform like duties for the committees when required. The Secretary shall have the custody of the seal. The Secretary shall have the custody of the stock books and shall perform such other duties as may be prescribed by the Board of Directors or the Chairman of the Board and the Chief Executive Officer.

Section 7. Duties of Treasurer. The Treasurer shall have the custody of the corporate funds and securities and shall keep full and accurate accounts of receipts and disbursements in books of the Company and shall deposit all monies and other valuable effects in the name and to the credit of the Company in such depositories as may be designated by the Board of Directors. The Treasurer shall disburse the funds of the Company as may be ordered by the Board, taking proper vouchers for such disbursements and shall render to the Chairman of the Board, the Chief Executive Officer and to the Board of Directors at its regular meetings or whenever they may require it, an account of all his transactions as Treasurer and of the financial condition of the Company.

Section 8. Duties of Other Officers. All other officers of the Company shall have such duties as shall be prescribed by the Board of Directors, the Chairman of the Board, and the Chief Executive Officer.

Section 9. Delegation of Duties of Officers. In the case of the absence of any officer of the Company or for any other reason that the Board may deem sufficient, the Board may delegate the powers or duties of any officer to any other officer or to any director for such time as determined by the Board.

Section 10. Compensation of Officers. The compensation of the Chairman of the Board and the Chief Executive Officer shall be determined by the Board of Directors. The compensation of each of the other officers shall be recommended by the Chief Executive Officer and approved by the Board of Directors. No officer shall be prevented from receiving such salary by reason of the fact that he is also a director of the Company.

ARTICLE V

INDEMNIFICATION

Section 1. Actions, Suits or Proceedings Other than by or in the Right of the Company. The Company shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative, including all appeals, (other than an action by or in the right of the Company) by reason of the fact that he is or was or has agreed to become a director or officer of the Company, or is or was serving or had agreed to serve at the request of the Company as a director or officer of another corporation (including a subsidiary of the corporation, or subsidiaries of subsidiaries), partnership, joint venture, trust or other enterprise, or by reason of any action alleged to have been taken or omitted in such capacity, against costs, charges, expenses (including attorneys' fees), judgments, fines, penalties and amounts paid in settlement actually and reasonably incurred by him or on his behalf in connection with such action, suit or proceeding and any appeal therefrom, if he acted in good faith and in a manner he reasonably believed to be within the scope of his authority and in, or not opposed to, the best interests of the Company, and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. The termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which he reasonably believed to be within the scope of his authority and in, or not opposed to, the best interests of the Company and, with respect to any criminal action or proceeding, had reasonable cause to believe that his conduct was unlawful.

Section 2. Actions or Suits by or in the Right of the Company. The Company shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, including all appeals, by or in the right of the Company to procure a judgment in its favor by reason of the fact that he is or was or has agreed to become a director or officer of the Company or is or was serving or has agreed to serve at the request of the Company as a director or officer of another corporation (including a subsidiary of the corporation or subsidiaries of subsidiaries), partnership, joint venture, trust or other enterprise, or by reason of any action alleged to have been taken or omitted in such capacity, against costs, charges and expenses (including attorneys' fees) actually and reasonably incurred by him or on his behalf in connection with the defense or settlement of such action or suit and any appeal therefrom, if he acted in good faith and in a manner he reasonably believed to be within the scope of his authority and in, or not opposed to, the best interests of the Company, except that no indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the Company unless and only to the extent that the Courts of South Dakota or the court in which such action or suit was brought shall determine upon application that, despite the adjudication of such liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such costs, charges and expenses which the Courts of South Dakota or such other court shall deem proper.

Section 3. Indemnification for Costs, Charges and Expenses of Successful Party. Notwithstanding the other provisions of this Article V, to the extent that a director or officer has been successful, on the merits or otherwise, including, without limitation, the dismissal of an action without prejudice, in defense of any action, suit or proceeding referred to in Sections 1 and 2 of this Article V, or in defense of any claim, issue or matter therein, he shall be indemnified against all costs, charges and expenses (including attorneys' fees) actually and reasonably incurred by him or on his behalf in connection therewith.

Section 4. Determination of Right to Indemnification. Any indemnification under Sections 1 and 2 of this Article V (unless ordered by a court) shall be paid by the Company unless a determination is made (i) by the board of directors by a majority vote of the directors who were not parties to such action, suit or proceeding, or if such majority of disinterested directors so directs, (ii) by independent legal counsel in a written opinion, or (iii) by the shareholders, that indemnification of the director or officer is not proper in the circumstances because he has not met the applicable standard of conduct set forth in Sections 1 and 2 of this Article V.

Section 5. Advance of Costs, Charges and Expenses. Costs, charges and expenses (including attorneys' fees) incurred by a person referred to in Sections 1 or 2 of this Article V in defending a civil or criminal action, suit or proceeding shall be paid by the Company in advance of the final disposition of such action, suit or proceeding; provided, however, that the payment of such costs, charges and expenses incurred by a director or officer in his capacity as a director or officer (and not in any other capacity in which service was or is rendered by such person while a director or officer) in advance of the final disposition of such action, suit or proceeding shall be made only upon receipt of an undertaking by or on behalf of the director or officer to repay all amounts so advanced in the event that it shall ultimately be determined that such director or officer is not entitled to be indemnified by the Company as authorized in this Article V. Such costs, charges and expenses incurred by other employees and agents may be so paid upon such terms and conditions, if any, as the majority of the directors deems appropriate. The majority of the directors may, in the manner set forth above, and upon approval of such director or officer of the Company, authorize the Company's counsel to represent such person, in any action, suit or proceeding, whether or not the Company is a party to such action, suit or proceeding.

Section 6. Procedure of Indemnification. Any indemnification under Sections 1, 2 and 3, or advance of costs, charges and expenses under Section 5 of this Article V shall be made promptly, and in any event within 60 days, upon the written request of the director or officer. The right to indemnification or advances as granted by this Article V shall be enforceable by the director or officer in any court of competent jurisdiction, if the Company denies such request, in whole or in part, or if no disposition thereof is made within 60 days. Such person's costs and expenses incurred in connection with successfully establishing his right to indemnification, in whole or in part, in any such action shall also be indemnified by the Company. It shall be a defense to any such action (other than an action brought to enforce a claim for the advance of costs, charges and expenses under Section 5 of this Article V where the required undertaking, if any, has been received by the Company) that the claimant has not met the standard of conduct set forth in Sections 1 or 2 of this Article V, but the burden of proving such defense shall be on the Company. Neither the failure of the Company (including its board of directors, its independent legal counsel and its shareholders) to have made a determination prior to the commencement of such action that indemnification of the claimant is proper in the circumstances because he has met the applicable standard of conduct set forth in Sections 1 or 2 of this Article V, nor the fact that there has been an actual determination by the Company (including its board of directors, its independent legal counsel and its shareholders) that the claimant has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that the claimant has not met the applicable standards of conduct.

Section 7. Settlement. The Company shall not be obligated to reimburse the costs of any settlement to which it has not agreed. If in any action, suit or proceeding, including any appeal, within the scope of Sections 1 or 2 of this Article V, the person to be indemnified shall have unreasonably failed to enter into a settlement thereof offered or assented to by the opposing party or parties in such action, suit or proceeding, then, notwithstanding any other provision hereof, the indemnification obligation of the Company to such person in connection with such action, suit or proceeding shall not exceed the total of the amount at which settlement could have been made and the expenses incurred by such person prior to the time such settlement could reasonably have been effected.

Section 8. Subsequent Amendment. No amendment, termination or repeal of this Article V or of relevant provisions of the South Dakota corporation law or any other applicable laws shall affect or diminish in any way the rights of any director or officer of the Company to indemnification under the provisions hereof with respect to any action, suit or proceeding arising out of, or relating to, any actions, transactions or facts occurring prior to the final adoption of such amendment, termination or repeal.

Section 9. Other Rights, Continuation of Right to Indemnification. The indemnification provided by this Article V shall not be deemed exclusive of any other rights to which a director, officer, employee or agent seeking indemnification may be entitled under any law (common or statutory), agreement, vote of shareholders or disinterested directors or otherwise, both as to action in his official capacity and as to action in any other capacity while holding office or while employed by or acting as agent for the Company, and shall continue as to a person who has ceased to be a director, officer, employee or agent, and shall inure to the benefit of the estate, heirs, executors and administrators of such person. Nothing contained in this Article V shall be deemed to prohibit, and the Company is specifically authorized to enter into, agreements with officers and directors providing indemnification rights and procedures different from those set forth herein. All rights to indemnification under this Article V shall be deemed to be a contract between the Company and each director or officer of the Company who serves or served in such capacity at any time while this Article V is in effect. This Article V shall be binding upon any successor corporation to this Company, whether by way of acquisition, merger, consolidation or otherwise.

Section 10. Savings Clause. If this Article V or any portion hereof shall be invalidated on any ground by any court of competent jurisdiction, then the Company shall nevertheless indemnify each director or officer of the Company as to any costs, charges, expenses (including attorneys' fees), judgments, fines and amounts paid in settlement with respect to any action, suit or proceeding, whether civil, criminal, administrative or investigative, including an action by or in the right of the Company, to the full extent permitted by any applicable portion of this Article V that shall not have been invalidated and to the full extent permitted by applicable law.

Section 11. Subsequent Legislation. If the South Dakota law is amended after the adoption of this Article V to further expand the indemnification permitted to directors and officers of the Company, then the Company shall indemnify such persons to the fullest extent permitted by the South Dakota law, as so amended.

ARTICLE VI

CAPITAL STOCK

Section 1. Stock Certificates. Certificates for stock of the Company shall be in such form as the Board of Directors may from time to time prescribe and shall be signed by the President or a Vice President and by a Treasurer or an Assistant Treasurer or the Secretary or an Assistant Secretary. If certificates are signed by a transfer agent, acting in behalf of the Company, or registered by a registrar, the signatures of the officers of the Company may be facsimile. The Company, through its officers, may cause certificates to be issued and delivered bearing facsimile signatures of persons even though at the time of the issuance and delivery of such certificates, any of such persons may no longer be an officer of the Company.

Section 2. Transfer Agent. The Board of Directors shall have power to appoint one or more transfer agents and registrars for the transfer and registration of certificates of stock of any class and may require that stock certificates shall be countersigned and registered by one or more of such transfer agents and registrars. The transfer agent and registrar may be the same person.

Section 3. Transfer of Stock. Shares of the capital stock of the Company shall be transferable on the books of the Company only by the holder of record thereof in person or by a duly authorized attorney upon surrender and cancellation of certificates for a like number of shares properly endorsed.

Section 4. Lost Certificate. In case any certificates of the capital stock of the Company shall be lost, stolen or destroyed, the Company may cause replacement certificates to be issued upon such proof of the fact and such indemnity to be given to it and to its transfer agent and registrar, if any, as shall be deemed necessary or advisable by it.

Section 5. Holder of Record. The Company shall be entitled to treat the holder of record of any share or shares of stock as the holder thereof in fact and shall not be bound to recognize any equitable or other claim to or interest in such shares on the part of any other person, whether or not it shall have express or other notice thereof, except as otherwise expressly provided by law. The expression "stockholder" or "shareholders" whenever used in these Bylaws shall be deemed to mean only the holder or holders of record of stock.

Section 6. Closing of Transfer Books. The Board of Directors shall have power to close the stock transfer books of the Company for a stated period but not to exceed, in any case, fifty days, and in case of a meeting of shareholders not less than ten days, preceding the date of any meeting of shareholders, or the date for payment of any dividend, or the date for the allotment of rights, or the date when any change or conversion or exchange of capital stock shall go into effect, or in order to make a determination of shareholders for any other proper purpose; provided, however, that in lieu of closing the stock transfer books, the Board of Directors may fix in advance a date as the record date for any such determination of shareholders, not less than ten days prior to the date on which the particular action, requiring such determination of shareholders, is to be taken; and in such case only such shareholders as shall be shareholders of record on the date so fixed shall be entitled to such notice of, and to vote at, such meeting, or to receive payment of such dividend, or to receive such allotment of rights, or to exercise such rights, as the case may be, notwithstanding any transfer of any stock on the books of the Company after any such record date fixed as aforesaid. When a determination of shareholders entitled to vote at any meeting of shareholders has been made as provided in this section, such determination shall apply to any adjournment thereof.

Section 7. Closing of Transfer Books to Authorize Increase in Indebtedness and Capital Stock. Notwithstanding Section 6 of this Article and in order to comply with Section 8 of Article XVII of the South Dakota Constitution, the notice to be given shareholders for a meeting at which a proposal to increase the Company's authorized indebtedness or capital stock is to be considered shall be given at least sixty days prior to the meeting and the record date for the determination of shareholders eligible to vote at such meeting may be set by the Board sixty or more days prior to the said meeting.

ARTICLE VII

CONTRACTS, LOANS, CHECKS AND DEPOSITS

Section 1. Contracts. The Board of Directors may authorize any officer or officers, agent or agents, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Company, and such authority may be general or confined to specific instances.

Section 2. Loans. No loans shall be contracted on behalf of the Company and no evidences of indebtedness shall be issued in its name unless authorized by a resolution of the Board of Directors. Such authority may be general or confined to specific instances.

Section 3. Checks, Drafts, etc. All checks, drafts, or other orders for the payment of money, notes or other evidences of indebtedness issued in the name of the Company shall be signed by such officer or officers, agent or agents of the Company and in such manner as shall from time to time be determined by resolution of the Board of Directors.

Section 4. Deposits and Investments. All funds of the Company not otherwise employed shall be deposited from time to time to the credit of the Company in such banks, trust companies or other depositories as the Board of Directors or officers of the Company designated by the Board of Directors may select; or be invested as authorized by the Board of Directors. Such authority may be general or confined to specific instances.

ARTICLE VIII

MISCELLANEOUS

Section 1. Offices. The principal office of the Company shall be in the City of Rapid City, County of Pennington, State of South Dakota. The Company may also have offices at such other places within or without the State of South Dakota as the Board of Directors may from time to time designate or as the business of the Company may require.

Section 2. Seal. The corporate seal shall have inscribed thereon the name of the Company and the words "Corporate Seal — 2000 — South Dakota."

Section 3. Audit. The books of account of the Company shall be audited annually by an independent firm of public accountants who shall be appointed by the Board of Directors and ratified by the shareholders at each annual meeting. Such auditors shall submit to the Board of Directors each year certified financial statements of the Company for the preceding fiscal year.

ARTICLE IX

AMENDMENTS

These Bylaws may be altered, amended or repealed at any meeting of the Board of Directors by the affirmative vote of a majority of the whole Board; provided, no alteration or amendment may be in conflict with any provision of the Articles of Incorporation.

Dated this 20th day of December, 2002.

By: /s/ Steven J. Helmers
Steven J. Helmers, Secretary

Exhibit 10.10

FIRST AMENDMENT TO PENSION EQUALIZATION PLAN

OF BLACK HILLS CORPORATION

Pursuant to action taken by the Board of Directors of Black Hills Corporation, the Pension Equalization Plan of Black Hills Corporation (as amended effective November 6, 2001) is hereby amended as follows:

I.

Effective December 20, 2002, Section 3 is amended to read as follows:

> "Earnings" shall mean the compensation paid to an employee by a Company during a calendar year, including any amounts paid to him as overtime, bonus, commission, unused paid time off or incentive compensation, any earnings reduction under a cash or deferred arrangement established under Section 401(k) of the Code, any earnings reduction under a Nonqualified Deferred Compensation Plan, any salary reduction under a flexible benefit program established by the Company under Section 125 of the Code and, effective January 1, 2000, any compensation reduction elected for qualified transportation fringe benefits under Section 132 (f)(4) of the Code, but excluding reimbursements and expense allowances, taxable fringe benefits, moving expenses, moving/relocation allowances, non-cash incentives and stock options, long-term incentive compensation (such as payments under the Black Hills Corporation Omnibus Incentive Compensation Plan), payments received from a Nonqualified Deferred Compensation Plan and welfare benefits (such as group term life insurance in excess of $50,000 and tuition assistance).

IN WITNESS WHEREOF, Black Hills Corporation has caused this amendment to the **PENSION EQUALIZATION PLAN OF BLACK HILLS CORPORATION** to be executed this 29th day of January, 2003.

BLACK HILLS CORPORATION

By: /s/ Steven J. Helmers
Steven J. Helmers
Its: General Counsel and Secretary

BLACK HILLS CORPORATION

ACTIVE WHOLLY OWNED DIRECT AND INDIRECT SUBSIDIARIES

Acquisition Partners, LP, a New York limited partnership

Adirondack Hydro – Fourth Branch, LLC, a New York limited liability company

Adirondack Hydro Development Corporation, a Delaware corporation

Adirondack Operating Services, LLC, a New York limited liability company

Black Hills Acquisition Corp., a Colorado corporation

Black Hills Colorado, LLC, a Delaware limited liability company

Black Hills Energy Capital, Inc., 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

Black Hills Fiber Systems, Inc., a South Dakota corporation

Black Hills FiberCom, LLC, a South Dakota limited liability company

Black Hills Fountain Valley, LLC, a Delaware limited liability company

Black Hills Generation, Inc., a Wyoming 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 Operations, LLC, a Delaware limited liability company

Black Hills Nevada Real Estate Holdings, LLC, a Delaware limited liability company

Black Hills Nevada, LLC, a Delaware limited liability company

Black Hills North America, Inc., a Delaware corporation

Black Hills Operating Company, LLC, a Delaware limited liability company

Black Hills Power, Inc., a South Dakota corporation

Black Hills Southwest, LLC, a Delaware limited liability company

Black Hills Valmont Colorado, Inc., a Delaware corporation

Daksoft, Inc., a South Dakota corporation

E NextA 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 corporation

Hudson Falls, LLC, a New York limited liability company

Indeck North American Power Fund, LP, a Delaware limited partnership

Indeck North American Power Partners, LP, a Delaware limited partnership

Indeck Pepperell Power Associates, Inc., a Delaware corporation

Landrica Development Company, a South Dakota corporation

Las Vegas Cogeneration Energy Financing Company, LLC, a Delaware limited liability company

Las Vegas Cogeneration II, LLC, a Delaware limited liability company

Middle Falls Corporation, a New York Corporation

Middle Falls II, LLC, a New York limited liability company

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

NYSD Limited Partnership, a New York limited partnership

NYSD Partners, LLC, a New York limited liability company

Sissonville Corporation, a New York corporation

Sissonville II, LLC, a New York limited liability company

Sissonville Partners, LLC, a New York limited liability company

Sissonville Limited Partnership, a New York limited partnership

South Glens Falls, LLC, a Delaware limited liability company

State Dam Corporation, a New York corporation

State Dam II, LLC, a New York limited liability company

Sunco Ltd., LLC, a Nevada limited liability company

Warrensburg Corporation, a New York corporation

Warrensburg Hydro Power Limited Partnership, a New York limited partnership

Warrensburg II Corporation, a New York corporation

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, 2003 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS 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, 2002.

DELOITTE & TOUCHE

Minneapolis, Minnesota
March 25, 2003

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 Associates, Inc.

March 27, 2003

Exhibit 99.1

BLACK HILLS CORPORATION

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 period ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Daniel P. Landguth, Chairman of the Board 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 result of operations of the Company.

/s/ Daniel P. Landguth

Daniel P. Landguth
Chairman of the Board and
Chief Executive Officer
March 27, 2003

Exhibit 99.2

BLACK HILLS CORPORATION

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 period ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Mark T. Thies, Senior 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 result of operations of the Company.

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President and
Chief Financial Officer
March 27, 2003