UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K/A
(Amendment No. 1)

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

For the fiscal year ended December 31, 2000

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 333-52664

BLACK HILLS CORPORATION

Incorporated in South Dakota IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

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

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

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

Indicate by check mark 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

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

At February 28, 2001 $843,247,880

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, 2001
Common stock, $1.00 par value	22,951,394 shares

Documents Incorporated by Reference
1. Definitive Proxy Statement of the Registrant filed pursuant to Regulation 14A for the 2001 Annual Meeting of Stockholders to be held on May 30, 2001, is incorporated by reference in Part III.

FORWARD-LOOKING STATEMENTS

This Form 10-K includes "forward-looking statements" as defined by the Securities and Exchange Commission. These statements concern our plans, expectations and objectives for future operations. 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. The words "believe," "plan," "intend," "anticipate," "estimate," "project" and similar expressions are also intended to identify forward-looking statements. These forward-looking statements include, among others, such things as:

- expansion and growth of our business and operations;
- future financial performance;
- future acquisition and development of power plants;
- future production of coal, oil and natural gas;
- reserve estimates; and
- business strategy.

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 which could cause actual results to differ materially from those contained in the forward-looking statements, including the following factors:

- prevailing governmental polices 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;
- changes in and compliance with environmental and safety laws and policies;
- weather conditions;
- population growth and demographic patterns;
- competition for retail and wholesale customers;
- pricing and transportation of commodities;
- 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;
- capital market conditions;
- technological advances;
- competition for new energy development opportunities; and
- legal and administrative proceedings that influence our business and profitability.

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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

We are a growth oriented, diversified energy holding company operating principally in the United States. Our regulated and unregulated businesses have expanded significantly in recent years. Our independent energy group produces and markets power and fuel. 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 nationwide. We also own Black Hills Power, Inc., an electric utility serving approximately 58,600 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 growth over the last five years, primarily as a result of the expansion of our independent energy business and increases in wholesale electric sales.

	2000	1999	1998	1997	1996
Net income (in thousands):					
Electric utility	$ 37,105	$ 27,286	$ 24,825	$ 22,106	$ 18,333
Independent energy	28,946	11,882	10,068	10,471	12,132
Communications and other	(13,203)	(2,101)	(280)	(218)	(213)
Oil and gas write-down	--	--	(8,805)	--	--
	$ 52,848	$ 37,067	$ 25,808	$ 32,359	$ 30,252
Earnings per share	$2.37	$1.73	$1.60(2)	$1.49	$1.40
Assets (in thousands)	$1,320,320	$668,492	$559,417	$508,741	$467,354
Capital expenditures (in thousands)	$177,189(1)	$154,609	$27,225	$28,319	$24,388
Electric sales (megawatthours):					
Regulated utility					
Firm electric sales	1,973,066	1,920,005	1,923,331	1,932,347	1,710,571
Wholesale off-system	684,378	445,712	371,104	279,612	249,100
Total utility	2,657,444	2,365,717	2,294,435	2,211,959	1,959,671
Non-regulated sales	236,279	-	-	-	-
Total electric sales	2,893,723	2,365,717	2,294,435	2,211,959	1,959,671
Average daily marketing volumes:					
Natural gas (MMbtus)	860,800	635,500	524,800	231,000	28,200(3)
Crude oil (barrels)	44,300	19,270	19,000	12,600(3)	-
Coal (tons)	4,400	4,500	4,400(3)	-	-
Generating capacity (megawatts)					
Utility (owned generation)	393	353	353	353	353
Utility (purchased capacity)	70	75	75	75	75
Independent power	250	--	--	--	--
Total generating capacity	713	428	428	428	428
Oil and gas reserves (MMcfe)	44,882	44,114	30,160	24,022	17,330

(1) Excludes the non-cash acquisition of Indeck Capital, Inc.
(2) Excludes 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) Since date of inception of marketing operations.

For additional information on our business segments see - "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and Note 13 of NOTES TO CONSOLIDATED FINANCIAL STATEMENTS."

Holding Company Formation

At our annual meeting of shareholders on June 20, 2000, our shareholders approved the formation of a holding company structure through a "plan of exchange" between Black Hills Corporation and Black Hills Holding Corporation. The plan of exchange provided that each share of Black Hills Corporation common stock would be exchanged for one share of common stock of the holding company.

On December 22, 2000, articles of exchange were filed with the South Dakota Secretary of State. As a result:

- all common shareholders of Black Hills Corporation became shareholders of Black Hills Holding Corporation, the holding company;

- Black Hills Corporation became a wholly-owned subsidiary of Black Hills Holding Corporation;

- Black Hills Corporation changed its name to "Black Hills Power, Inc." and the holding company changed its name to "Black Hills Corporation"; and

- the debt securities and other financial obligations of Black Hills Power, Inc. continue to be the obligations of Black Hills Power, Inc.

The formation of our holding company structure allows us to pursue, through separate subsidiaries, business opportunities in both regulated and unregulated markets.

Industry Overview

In the last decade, many U.S. regulatory bodies have taken 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. In particular, the electric power industry is undergoing substantial change as a result of regulatory initiatives at the federal and state levels. As early as the mid-1990's, new regulatory initiatives to increase competition in the domestic power generation industry had been adopted or were being considered at the federal level and by many states. 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 into competitive or partially regulated businesses. This resulted in new investment opportunities to enter previously non-competitive or closed markets.

In 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636, followed by Order 888 in 1996, to increase competition by easing entry into natural gas and electricity markets. These orders require owners and operators of natural gas and power transmission systems to make transmission service available on a non-discriminatory basis to energy suppliers. In order to better assure competitive access to the transmission network on a non-discriminatory basis, FERC issued Order 2000 in December 1999, which encourages electric utilities with power transmission assets to voluntarily form regional transmission organizations to provide regional management and control of transmission assets independent of firms that sell electricity.

The electric power industry has also witnessed growing consumer demand and increasingly frequent regional shortages of electricity over the past three years. The summers of 1998, 1999 and 2000 and the winter of 2000-2001 have all been characterized by very high peak prices for electricity in a number of recently created wholesale electricity markets. We believe that substantial amounts of new electric generating capacity need to be built to relieve shortages of electricity and to replace inefficient and obsolete facilities.

The oil and gas industry has experienced strong increases in commodity prices since the historically low levels experienced in 1998. These price increases have been driven in part by several years of modest drilling activity combined with strong growth in demand for energy commodities. Continued growth of the Internet and other high technology industries is contributing to increasing demand for power. Demand for natural gas is expected to remain strong as an increasing number of gas-fired power plants are brought into service.

The telecommunications industry is currently undergoing widespread changes brought about by, among other things, the Telecommunications Act of 1996, the decisions of federal and state regulators to open the monopoly local telephone and cable television markets to competition and the need for higher speed, higher capacity networks to meet the increasing consumer demand for expanded telecommunications services, including broader video choices and high speed data and Internet services. The convergence of these trends and the inherent limitations of most existing networks have created opportunities for new types of communications companies capable of providing a wide range of voice, video and data services through new and advanced high speed, high capacity telecommunications networks.

As a result of historical and anticipated regulatory initiatives and the increasing demand for electricity, fuel and broadband services, we believe there are significant opportunities for the development and growth of our independent energy businesses, our regulated utility and our communications business.

Strategy

Our strategy is to build long-term shareholder value by deploying our development, operating and marketing expertise in the energy industry. We plan to operate a mix of unregulated independent energy and regulated utility businesses, with emphasis on the independent power generation and fuel production segments. We expect our independent energy businesses to operate nationwide, with an integrated regional emphasis on the western half of the United States. Our utility and communications businesses intend to continue focusing their retail operations primarily on the northern Black Hills region of South Dakota, with wholesale power sales concentrated primarily in the Rocky Mountain and West Coast regions.

Our strategy includes the following key elements:

- grow our independent power unit by developing and acquiring power projects primarily in the western United States;

- expand the generating capacity of our existing sites through a strategy known as "brownfield development;"

- sell a large percentage of the production from our independent power projects through long-term contracts in order to secure attractive investment returns;

- increase our reserves of natural gas and crude oil and expand our coal production;

- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;

- exploit our knowledge and market expertise while managing the risks inherent in fuel marketing;

- build and maintain strong relationships with wholesale energy customers; and

- capitalize on our utility's established market presence, relationships and customer loyalty.

Grow our Independent Power Unit by Developing and Acquiring Power Projects Primarily in the Western United States. Our aim is to continue the development of 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 aims 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 Rocky Mountain 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 Rocky Mountain and West Coast regions will continue 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.

Expand the Generating Capacity of Our Existing Sites Through a Strategy Known as "Brownfield Development." 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 are currently expanding our capacity with brownfield development underway at our Arapahoe, Valmont and Wygen sites, and believe that our Fountain Valley and Wygen sites in particular provide further opportunities for a significant expansion of our gas- and coal-fired generating capacity over the next several years.

Sell a Large Percentage of the Production From Our Independent Power Projects Through Long-Term Contracts in Order to Secure Attractive Investment Returns. Recent extreme price volatility in the short-term power markets are resulting in greater demand among our wholesale customers for mid- and long-term power purchase agreements. 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. In recent months, for example, we have entered into long-term tolling agreements covering nearly all of the gas-fired energy and capacity our independent power unit is adding through brownfield expansion of the Arapahoe and Valmont sites and from the Fountain Valley project. See "--Independent Energy -- Independent Power Plants."

Increase Our Reserves of Natural Gas and Expand Our Coal 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 and coal production. Our strategy is to expand our natural gas reserves through a combination of acquisitions and drilling programs and 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, and 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:

o substantially increase our natural gas reserves and minimize exploration risk by focusing on lower-risk exploration and development drilling as well as acquisitions of proven producing properties;

o exploit our belief that the long-term demand for natural gas will remain strong by emphasizing natural gas, rather than oil, in our acquisition and drilling activities;

o 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;

o increase coal production and sales from our Wyodak mine by continuing to develop additional mine-mouth generating facilities at the site, including the Wygen I plant, which is scheduled for completion in spring 2003; and

o pursue future sales of coal from the Wyodak mine to rail-served customers by reducing the moisture content of our coal so that we can ship it greater distances.

Exploit Our Fuel Cost Advantage 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. We intend to utilize a low-cost power production strategy, together with access to coal and natural gas reserves, to protect our revenue stream as an increasing number of gas-fired power plants are brought into operation. 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 have aggressively managed 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.

Exploit Our Knowledge and Market Expertise While Managing the Risks Inherent in Fuel Marketing. We aim to apply our knowledge of and expertise in the natural gas transmission system and trading markets in the western and northwestern regions of the United States and western Canada in order to exploit market inefficiencies and maximize our profits in our fuel marketing businesses. Our fuel marketing operations require effective management of price, counterparty and operational risks. To mitigate these risks, we have implemented risk management policies and procedures for each of our marketing companies that prohibit speculative strategies and establish price risk exposure levels, counterparty credit limits and 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 and by avoiding the issuance of parent company performance guarantees to counterparties of our marketing companies.

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.

We have been successful in entering into a variety of wholesale contracts based on the specific needs of our customers. For example, in 1999, Public Service Company of Colorado approached us to take over ownership and construction of the 120 megawatt Arapahoe and Valmont facilities in Colorado. Public Service Company of Colorado was subject to regulatory constraints that restricted its ability to own the facilities and needed the plants completed in an efficient and timely manner to meet the rapid growth in demand. We completed construction of the facilities on schedule, and signed tolling agreements with Public Service Company of Colorado for the capacity and energy generated by the original facilities. We subsequently signed agreements to expand the projects by 90 megawatts. In addition, we recently acquired 240 megawatts at the Fountain Valley site in Colorado which we expect to be in service in 2001. We have signed tolling agreements with Public Service Company of Colorado for the expanded facilities and the Fountain Valley site.

Capitalize On Our Utility's Established Market Presence, Relationships and Customer Loyalty. 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 independent energy and communications businesses. In addition, industry, technical and market expertise from our utility supports the growth of our independent energy businesses, and our strong brand recognition assists us in achieving rapid customer acceptance of our bundled communications services in our Black Hills service territory.

Independent Energy

Our independent energy group engages in the production and sale of electric power through ownership of a diversified portfolio of generating plants, the production of coal, natural gas and crude oil primarily in the Rocky Mountain region, and the marketing of fuel products nationwide. The independent energy group was our primary source of revenue and net income growth in 2000 and the net income from the independent energy group is expected to exceed net income from our regulated utility beginning in 2001. The independent energy group consists of three units: independent power production, fuel production and fuel marketing.

Independent Power Production. Our independent power production business acquires, develops and expands unregulated power plants. We hold varying interests in operating independent power plants in California, New York, Massachusetts and Colorado with a total net ownership of 210 megawatts, as well as minority interests in several power-related funds with a net ownership interest of 40 megawatts.

Project Development Program. In February 2001, we signed a definitive agreement with Enron Corporation to purchase 100 percent of an independent power project under construction near Colorado Springs, Colorado and known as the "Fountain Valley" project. We expect to close this transaction on or about March 31, 2001. This site will initially house 240 megawatts of gas-fired peaking facilities. The energy and capacity generated by the Fountain Valley project will be sold to Public Service Company of Colorado under a tolling contract expiring in July 2012 pursuant to which we assume no fuel cost risk. We expect the plant to be completed in phases beginning in June 2001 and ending in July 2001 with the total cost expected to approximate $175 million. In addition to the current project, we believe that the Fountain Valley site provides us with attractive expansion and integration opportunities and is well-situated to serve other markets in the Rocky Mountain and southwest regions.

In addition to Wygen I and the Fountain Valley development, other projects under construction include:

- Arapahoe CC5, a 50 megawatt combined cycle expansion of our gas-fired turbines at the Arapahoe site located in the Front Range of Colorado;

- Valmont Unit 8, a 40 megawatt gas-fired turbine addition to our Valmont site located in the Front Range of Colorado;

- Black Hills Generation Gillette CT, a 40 megawatt gas-fired facility located at the same site as our Wygen I plant; and

- Harbor Expansion, a 30 megawatt (10 megawatt net ownership interest) expansion of our Harbor Cogeneration facility located in Wilmington, California.

We also have an active acquisition and development program through which we are pursuing a number of additional generation projects in various stages of development, including the following:

- the Lange project, a 40 megawatt gas-fired turbine to be located either at the same site as our Wygen I and Black Hills Generation CT plants near Gillette, Wyoming, or adjacent to our transmission system in Rapid City, South Dakota, and which we expect to compete in early 2002;

- 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, which we expect to complete in 2005;

- three separate projects in early stage development with a total of 1,100 megawatts of generation to be located at sites we currently own in whole or in part; and

- four additional early stage development projects with a total of 1,340 megawatts of generation at new sites which we do not currently control.

No assurance can be given 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 diversification and balance in our portfolio of regulated and unregulated power plants. Our portfolio (including plants currently operating and those under construction) is diversified in terms of fuel mix and geographic location, with 81 percent of net unregulated capacity being gas-fired, 13 percent coal-fired, and the remainder hydroelectric. Our independent power plants are located in California, Wyoming, South Dakota, Colorado, New York and Massachusetts. In contrast, our electric utility capacity is approximately 53 percent coal-fired, 33 percent oil or gas-fired, and 14 percent under purchased power contracts, with plants located in South Dakota and Wyoming.

We also have a diversified mix of revenue sources. We typically sell two types of products: energy and capacity, including ancillary services. Although these are separate products, both are typically sold together. Energy refers to the actual electricity generated by our facilities for ultimate transmission and distribution to consumers of electricity. Energy is the only one of our products that is subsequently distributed to consumers. Capacity refers to the physical capability of a facility to produce energy. Ancillary services generally are capacity support products used to ensure the safe and reliable operation of the electric power supply system. Examples of ancillary services include:

- automatic generation control, which is used to balance energy supply with energy demand, referred to in our industry as "load," on a real-time basis; and

- operating reserves, which are used on an hourly or daily basis to generate additional energy if demand increases or if major generating resources go off-line or if transmission facilities become unavailable.

Our output is sold under contracts of varying length and subject to merchant pricing, thereby allowing us to take advantage of current favorable price trends, while hedging the impact of a potential downturn in prices in the future. We currently sell energy and capacity under a combination of short- and long-term contracts as well as direct sales into the merchant energy markets. Currently, we sell 70 percent to 80 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 merchant markets. The energy and capacity generated by our Arapahoe and Valmont projects, and the additional energy and capacity expected at these sites and at our Fountain Valley project upon its completion, are subject to long-term tolling agreements with Public Service Company of Colorado. Similarly, the electricity generated by the Adirondack Hydro facilities in New York is under a combination of short- and long-term agreements with Niagara Mohawk.

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 current focus has been, and is likely to remain, in the North American Reliability Council region known as the Western Systems Coordinating Council, or "WSCC." Among those factors we consider critical in evaluating the relative attractiveness of new generation opportunities are the following:

- electric demand growth potential in the targeted region;
- requirements for permitting and siting;
- 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.

We intend to target both acquisition and development opportunities which provide a minimum expected return on equity of 12 to 13 percent. We plan to concentrate on development projects over acquisitions because we believe that development projects generally offer us opportunities for higher rates of return.

Our goal is to sell approximately 80 percent of the independent power generation portfolio under long-term contracts, while leaving the remainder available for merchant, or "spot" sales. We aim to secure long-term power sales contracts in conjunction with non-recourse plant financing. This enables us to design a debt repayment schedule to closely match the term of the power sales contracts so that at the end of the contract term, the debt has typically been repaid.

Independent Power Plants

General. Power facilities are often classified by cost of production. Facilities that have the lowest costs of production relative to other power plants in the region are usually the facilities that are first used to provide energy. These plants are known as "baseload" facilities and typically operate more than 60 percent of the time they are available. Our hydroelectric assets in New York and the Wygen I coal-fired facility under construction in Wyoming are examples of low-cost, baseload plants.

As demand for electricity rises during the year or even during the course of a day, power plants that have higher costs of production are dispatched to supply additional energy. Facilities that regularly provide additional energy during a day and that are typically used between 10 percent and 60 percent of the time are known as "intermediate" facilities.

Power plants with the highest costs of production are called upon only in times of exceptionally high demand and are known as "peaking units." Peaking units are generally dispatched less than 10 percent of the time they are available.

Rocky Mountain and West Coast Facilities. We own approximately 151 megawatts of generating capacity in the WSCC states of California and Colorado, and are in the process of constructing or acquiring another 470 megawatts in the region. All of these facilities in operation are gas-fired, with all but our Harbor Cogeneration facility in California operating under long-term power purchase or tolling agreements. The Harbor Cogeneration facility currently operates as a merchant peaking plant selling ancillary services and energy into the California market.

WSCC Facilities

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
In Operation:						
Arapahoe Unit 5	Gas	CO	40.0	100%	40.0	2000
Arapahoe Unit 6	Gas	CO	40.0	100%	40.0	2000
Valmont Unit 7	Gas	CO	40.0	100%	40.0	2000
Ontario	Gas	CA	12.0	50%	6.0	1984
Harbor	Gas	CA	80.0	31.8%	25.4	1989
Total in Operation			212.0		151.4	
Under Construction:						
Fountain Valley	Gas	CO	240.0	100%	240.0	2001
Arapahoe CC5	Gas	CO	50.0	100%	50.0	2002
Valmont Unit 8	Gas	CO	40.0	100%	40.0	2001
Wygen I	Coal	WY	90.0	100%	90.0	2003
BHG Gillette CT	Gas	WY	40.0	100%	40.0	2001
Harbor Expansion	Gas	CA	30.0	31.8%	9.5	2001
Total in Construction			490.0		469.5	
Total WSCC			702.0		620.9	

Arapahoe, Valmont and Fountain Valley Facilities

In Operation: Our Arapahoe and Valmont plants are wholly-owned gas-fired peaking facilities in the Front Range of Colorado, with a total capacity of 120 megawatts. The projects were acquired from Public Service Company of Colorado in January 2000 jointly by the former Indeck Capital and us, and were put into service on June 1, 2000. We sell all of the output from these plants to Public Service Company of Colorado under tolling contracts expiring in May 2012. These contracts also cover the Fountain Valley project and the Arapahoe and Valmont expansion projects described below.

Under Construction: We expect to increase our capacity by 40 megawatts at the Valmont project by June 2001 and by 50 megawatts at the Arapahoe plant by May 2002.

The first phase of our 240 megawatt gas-fired Fountain Valley facility is scheduled for completion in June 2001, with final completion scheduled for July 2001. The Fountain Valley site, located in Colorado has ample capacity for subsequent expansion if market conditions prove to be attractive.

Wygen I Facility

The Wygen I facility is a leased mine-month coal-fired plant with a total capacity of 90 megawatts, which is expected to be completed by spring 2003. The Wygen I plant will be substantially identical in design to our electric utility's Neil Simpson II facility, completed in 1995. The two plants will both run 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 will use the latest available environmental control technology. We intend to sell the majority of the power from the facility under long-term unit contingent capacity and energy sales contracts, under which delivery is not required during plant outages. We have entered into a contract to sell 60 megawatts of unit contingent capacity from this plant to Cheyenne Light, Fuel and Power Company with a term of 10 years from the date the plant becomes operational. We have also signed a contract to sell an additional 20 megawatts of unit contingent capacity and energy to the Municipal Electric Agency of Nebraska for a term of 10 years.

Black Hills Generation Gillette CT

The Black Hills Generation Gillette CT facility, a gas-fired combustion turbine facility located at the same site as our Wygen I facility, has a total capacity of 40 megawatts and is scheduled to be completed in May 2001. We plan to utilize this facility as a merchant plant through summer 2001. Beginning in September 2001, we will sell the energy and capacity from this facility to Cheyenne Light, Fuel and Power Company under a 10-year unit contingent tolling agreement.

Ontario Cogeneration Facility

Ontario Cogeneration Company is a 12 megawatt, gas-fired power plant in Ontario, California, which is currently being operated 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 2002. For a description of certain issues relating to our operation of this plant, see "--Regulation--Environmental Regulation--Clean Air Act."

Harbor Cogeneration Facility

In Operation: Harbor Cogeneration, a gas-fired plant located in Wilmington, California, is currently being operated as a merchant peaking plant selling ancillary services and energy into the California Independent System Operator, or "CAISO," market. It formerly operated under a 30-year power purchase agreement with Edison Mission Energy. This contract was terminated in February 1999 under a settlement agreement with Southern California Edison. Under the buyout agreement, Harbor Cogeneration will receive payments pursuant to a termination payment schedule for an amount equal to the total payment under the original contract due for the 11-year period beginning April 1, 1997 and ending on October 1, 2008. The facility currently has no long-term debt outstanding.

Under Construction/Expansion: We are currently expanding the Harbor Cogeneration plant by an additional 30 megawatts (10 megawatt net ownership interest), with a targeted completion date of May 2001. The plant has sold the peaking capacity from its expansion to the CAISO for the peak summer periods of 2001 through 2003 under an agreement that provides for payments to us of $1 million per year for each of 2001, 2002 and 2003. We plan to sell the remaining capacity and all of the energy from this plant in the California market on a merchant basis.

Lange Project

In March 2001, we placed an order for a 40 megawatt gas-fired combustion turbine which will be located either adjacent to the Wygen I and our Black Hills Generation Gillette CT plants near Gillette, Wyoming, or at a new site adjacent to our transmission system in Rapid City, South Dakota, where we have received all necessary permits for the construction of two 40 megawatt combustion turbine facilities. We expect the first 40 megawatt turbine unit to be operational in early 2002.

Northeast Facilities. We currently own approximately 58 net megawatts of generation capacity in eight plants in the Northeast region, all of which are located in New York and Massachusetts. Sixty-seven percent of this generation is "run-of-river" hydroelectric, with the remainder being gas-fired peaking capacity.

Power Plant	Fuel Type	State	Total Capacity (MWs)	Interest	Net Capacity (MWs)	Start Date
Northeast						
New York State Dam	Hydro	NY	11.4	100%	11.4	1990
Middle Falls	Hydro	NY	2.3	50%	1.2	1989
Sissonville	Hydro	NY	3.0	100%	3.0	1990
Warrensburg	Hydro	NY	2.9	100%	2.9	1988
Hudson Falls	Hydro	NY	41.9	30.2%	12.7	1995
South Glens Falls	Hydro	NY	13.9	30.2%	4.2	1994
Fourth Branch	Hydro	NY	3.4	100%	3.4	1988
Pepperell	Gas	MA	40.0	48.7%	19.5	1990
Total (Northeast)			118.8		58.3	

Adirondack Hydro Development

The seven "run-of-river" hydroelectric plant interests acquired as a result of our acquisition of Indeck Capital 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.

We acquired approximately 10 percent of the Hudson Falls and the South Glens Falls plants as part of the Indeck Capital acquisition and an additional 20 percent of these plants in December 2000. These projects run at a high capacity factor because the Hudson River is regulated for power generation and flood control.

The seven projects were initially covered by long-term power purchase contracts with Niagara Mohawk for all or most of their output. Currently, three projects have been restructured to allow the power purchase contracts to be bought out and for us eventually to sell power into the New York Independent System Operator (NY-ISO). The New York State Dam, Sissonville, Fourth Branch and Warrensburg facilities are currently subject to short-term transition power sales agreements expiring in 2002 and 2003, at which point these plants will sell directly into the market on a merchant basis. 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 is currently subject to a tolling agreement with Enron Power and Trading for the sale of a majority of its energy for the year 2001, and a steam sales agreement with the Pepperell Paper Company expiring in November 2001.

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, as described below:

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	7	136.0	12.6%	17.1
Energy Investors Fund II	$115.0	$0	6	130.0	6.9%	9.0
Project Finance Fund III	$101.0	$0	7	239.0	5.3%	12.7
Caribbean Basin	$75.0	$60	1	34.0	3.7%	1.3
Total Fund Interests				539.0		40.1

Financing of Our Independent Power Projects. We have financed our principal independent power generation facilities primarily with non-recourse debt that is repaid solely from the project's revenues. This type of financing is referred to as "project financing." These financings generally are secured by the physical assets, major project contracts and agreements, cash accounts and, in certain cases, our ownership interest, in the related project. True project financing is not available for all projects, including some assets purchased out of bankruptcy, some merchant plants and some purchases of minority stock positions in publicly-traded companies. Even in those instances, however, we may still be able to finance a smaller portion of the total cost with project financing, with the remainder financed with debt that is either raised or supported at the corporate rather than the project level.

Project financing transactions generally are structured so that all revenues of a project are deposited directly with a bank or other financial institution acting as escrow or security deposit agent. These funds then are payable in a specified order of priority set forth in the financing documents to ensure that, to the extent available, they are used first to pay operating expenses, senior debt service and taxes and to fund reserve accounts. Thereafter, subject to satisfying debt service coverage ratios and certain other conditions, available funds may be disbursed for management fees or dividends or, where there are subordinated lenders, to the payment of subordinated debt service.

These project financing structures are designed to prevent the lenders from relying on us or our other projects for repayment; that is, they are "non-recourse" to us and our affiliates not involved in the project, unless we or another affiliate expressly agree to undertake liability. In the event of a foreclosure after a default, our project affiliate owning the facility would only retain an interest in the assets, if any, remaining after all debts and obligations were paid. In addition, the debt of each operating project may reduce the liquidity of our equity interest in that project because the interest is typically subject both to a pledge securing the project's debt and to transfer restrictions set forth in the relevant financing agreements. Also, our ability to transfer or sell our interest in certain projects or the project's power is restricted by certain purchase options or rights of first refusal in favor of our partners and certain change of control restrictions in the project financing documents.

Fuel Production

Coal

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 on top of the Powder River Basin, one of the largest coal reserves in the United States. We believe the Wyodak mine is the oldest operating surface coal mine in the nation, with an annual production of approximately three million tons. 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, 2000, we had coal reserves of 275 million tons, enough to satisfy present contracts for over 90 years. Substantially all of our coal production is sold under long-term contracts to Black Hills Power, Inc., our electric utility, and to PacifiCorp.

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 2013. For a description of litigation with PacifiCorp relating to this agreement, see "ITEM 3. LEGAL PROCEEDINGS - PacifiCorp Litigation."

In May 2000, we acquired the K-Fuel plant, a coal enhancement plant located near our Gillette, Wyoming coal mine. The plant, which transforms high-moisture, low-heat-value coal into low-moisture, high-heat-value coal, is currently not in service. We are working in conjunction with Denver-based KFx, Inc. to attract investors to make the capital improvements necessary to re-start the plant. If we do not locate suitable investment partners, the plant will not be re-started.

Over the next several years, we expect to increase coal production to supply:

- the Wygen I 90 megawatt mine-mouth power plant, which is scheduled for completion in 2003; and

- additional mine mouth generating capacity of up to 500 megawatts at the same site as the Wygen I plant, which is in the early stages of development.

In addition, if our K-Fuel plant is re-started, we expect to increase production from the Wyodak mine and market any low-moisture, high-heat content coal we produce to an expanded customer base.

Natural Gas and Crude Oil

Our oil and gas exploration and production segment operates approximately 298 oil and gas wells, all of which are located in Wyoming. 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 341 wells located in California, Montana, 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.

We plan to substantially increase our natural gas reserves and minimize exploration risk by focusing on lower-risk exploration and development drilling and acquisitions of proven producing properties. A key component of this strategy is the pursuit of shallow gas opportunities in the Rocky Mountain region. We also expect to modestly increase our California and offshore production in the future, but do not plan to serve as the operator for those production activities.

As of December 31, 2000, we had proved reserves of 4.4 million barrels of oil and 18.4 billion cubic feet of natural gas, with approximately 62 percent of current production consisting of natural gas. In 2000, our oil and gas production increased 12 percent over 1999 levels, with record drilling results and year-end reserves.

In March 2001, we signed a definitive agreement to purchase certain operating and non-operating interests in 74 oil and gas wells located primarily in Colorado and Wyoming. We expect this transaction to close in April 2001. These properties have proved reserves of approximately 8.7 billion cubic feet of natural gas and approximately 200,000 barrels of oil, representing an increase in our existing proved reserves of over 20 percent.

Fuel Marketing. We market natural gas, oil and coal in specific regions of the United States. We offer physical and financial wholesale fuel 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, coal mines, energy marketers and retail gas users. Our fuel marketing businesses collectively have 35 employees. Our average daily marketing volumes for the year ended December 31, 2000, were 860,800 million British thermal units of gas, 44,300 barrels of oil and 4,400 tons of coal.

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	Chicago, IL; Calgary, Alberta, Canada
Black Hills Energy Resources	Crude Oil	Houston, TX	Tulsa, OK; Midland, TX; Longview, TX
Black Hills Coal Network	Coal	Mason, OH	St. Clairsville, OH

Gas Marketing

Our natural gas marketing operations are headquartered in Golden, Colorado, with satellite offices in Calgary, Canada and Chicago, Illinois. Our gas marketing operations focus primarily on wholesale marketing and producer marketing services. Producer services include providing for direct purchases of wellhead gas and for risk transfer and hedging products. Our gas marketing efforts are concentrated in the Rocky Mountain and West Coast regions and in Western Canada, which are areas in which we believe we have a competitive advantage due to our knowledge of local markets. 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 concentrated primarily in Texas, Oklahoma, Louisiana and Arkansas. In July 1999, we acquired a 33 percent ownership interest in a 200-mile pipeline, with a capacity of 67,000 barrels of oil per day, that transports imported crude oil from Beaumont, Texas to refining and trading markets in northern regions.

Coal Marketing

We market coal to various industrial customers and power plants located primarily in the midwest and eastern regions of the United States through our coal marketing subsidiary, Black Hills Coal Network. We formed Black Hills Coal Network in 1998 to acquire the assets and hire the operational management of Coal Network and Coal Niche, based in Mason, Ohio. These predecessor companies were coal brokerage and agency companies with customers located primarily east of the Mississippi River.

Electric Utility - Black Hills Power, Inc.

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 utility capital expenditures, dividends, and overall performance and growth.

Distribution and Transmission. Our electric utility distribution and transmission businesses serve approximately 58,600 electric customers, with an electric transmission system of 447 miles of high voltage lines and 541 miles of lower voltage lines. 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 in 2000 is comprised of 29 percent wholesale off-system sales, 26 percent commercial, 20 percent residential, 14 percent industrial, 10 percent contract wholesale and 1 percent municipal. Approximately 68 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 for another five-years, through 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 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.

- Twenty-nine percent of our electric revenues for the year ended December 31, 2000 consisted of off-system sales compared to 8 percent in 1999 and 5 percent in 1998. Further increases in the volume of off-system sales are expected in the future due to demand growth in the Rocky Mountain region and the June 2000 addition of 40 megawatts of gas-fired generating capacity.

- Our system has the capability of connecting to either the midwestern or western transmission systems, which provides us with access between the WSCC region and the Mid-Continent Area Power Pool, or "MAPP" region. This allows us the opportunity to improve system reliability and take advantage of power price differentials between the two electric grids. We are able to transmit up to 80 megawatts of our generation into the MAPP. Alternatively, we can receive up to 20 megawatts of power from MAPP into our WSCC-based system. We expect to increase this capability to 50 megawatts in 2001 through an upgrade of our facilities at a cost of less than $1 million.

- We have firm transmission access to deliver up to 65 megawatts of power on PacifiCorp's system to wholesale customers in the western region.

On October 15, 2000, we indicated to FERC our intent to participate in a regional transmission organization, or RTO. Our transmission system is a part of the western transmission grid governed by the Western Systems Coordinating Council, and it interconnects with transmission systems operated by the Western Area Power Administration, or WAPA, and by PacifiCorp. WAPA is evaluating participation in the Desert Star RTO which will involve transmission systems in Colorado and the southwest region, while PacifiCorp is evaluating participation in the RTO West which will involve transmission systems in Wyoming and the northwest region. Neither Desert Star RTO nor RTO West has been formally organized at this time, but we expect that Desert Star RTO and RTO West will be making their final FERC filings late this year or in early 2002. If FERC approves these two RTOs, the organizations anticipate being fully operational in late 2002. We will continue to monitor the development of these two RTOs and decide in the future which RTO best fits our transmission system and operations.

Power Purchase Agreements. We sell approximately 40 percent of our utility's current load under long-term contracts. Our key contracts include a 10-year contract expiring in 2007 with Montana-Dakota Utilities Company 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 system and are treated as firm native load. In addition, we recently entered into an agreement with the Municipal Electric Agency of Nebraska for the sale of 30 megawatts of unit contingent energy and capacity for a period through the completion of construction of the Wygen I independent power facility, which is expected in spring 2003. For the 10-year period beginning with the completion of the Wygen I facility, our utility and our independent power unit will each provide 20 megawatts of unit contingent energy and capacity to the Municipal Electric Agency of Nebraska.

Our utility's electric load is served by coal-, oil- and natural gas-fired generating units providing 393 megawatts of generation capacity and from the following purchased power and capacity contracts with PacifiCorp:

- a power sales agreement expiring in 2023, involving the purchase by us of 65 megawatts of baseload power in 2001, and scheduled to decline to 50 megawatts by 2004;

- 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; and

- a capacity option call, which gives us an option to purchase up to 60 megawatts of peaking capacity seasonally through March 31, 2007.

Regulated Power Plants. Since 1995, our utility has been a net producer of energy. Our utility owns 393 megawatts of generating capacity, all of which is located in the Rocky Mountain region. Our utility's peak system load of 372 megawatts was reached in July 2000. 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
Neil Simpson I	Coal	WY	21.8	100%	21.8	1969
Neil Simpson II	Coal	WY	88.9	100%	88.9	1995
Osage	Coal	WY	34.5	100%	34.5	1948
Wyodak	Coal	WY	362.0	20%	72.4	1978
Neil Simpson CT	Gas	WY	40.0	100%	40.0	2000
Total			682.2		392.6	

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. Coal for the plant is purchased from our Wyodak mine and 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 put 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 put into service from 1977 to 1979, and are being operated as peaking units.

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 put into service in 1969. Neil Simpson II has a capacity of 88.9 megawatts and was put into service in 1995. These plants are operated as baseload facilities, and are mine-mouth coal-supplied plants, receiving their coal directly from the Wyodak mine.

Osage

The Osage plant is a wholly-owned coal-fired plant in Osage, Wyoming with a total capacity of 34.5 megawatts and was put into service from 1948 to 1952. This plant has three turbine generation units, and is being operated as a baseload plant. Coal for the plant is purchased from our Wyodak mine and 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 put into service in 1978, and is currently being operated as a baseload plant.

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 put into service in 2000, and was installed to provide peaking capabilities.

Communications

Our communications group, known as Black Hills FiberCom, was formed to provide state-of-the-art broadband telecommunications services to the underserved 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 210-mile inter- and intra-city fiber optic network and currently operate 588 miles of two-way interactive hybrid fiber coaxial or "HFC" cable. We believe we are one of the first companies in the United States to provide video entertainment service, high-speed Internet access, and local and long distance telephone services over an advanced broadband infrastructure. We have bundled these services into value packages with a single consolidated bill for all of these services.

We introduced our broadband communications services to the Rapid City and northern Black Hills areas in November 1999. As of December 31, 2000, we had attracted 8,368 residential customers and 646 business customers. Our goal is to double the number of our customers, and to attain 50 percent residential market penetration within our service territory while serving 35 percent of all broadband business customers in that territory.

The construction of our communications network is approximately 75 percent complete and we expect to substantially complete construction in 2001. We estimate that completing our network will require approximately $25 million of capital expenditures in 2001.

Competition

The independent power, fuel production and fuel 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. In particular, the independent power industry in recent years has been characterized by increased competition for asset purchases and development opportunities.

In addition, Congress has considered various pieces of legislation 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. Industry deregulation may encourage the disaggregation of vertically integrated utilities into separate generation, transmission and distribution businesses. 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 competition from numerous well established companies, including Qwest Communications, Rapid City's incumbent local exchange carrier, 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 services, our products and services and our ability to offer an attractive package of bundled products.

Risk Management

Our fuel marketing operations require efficient risk management of price, counterparty performance and operational risks. Price risk is created through 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 arises from a lack of internal controls. We have implemented controls to mitigate each of these risks.

Our fuel 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. These policies are established by our board of directors, reviewed on a regular basis and monitored as described below.

We maintain a working risk management committee for each of our marketing companies, and a credit committee at the parent company level. The risk management committees focus on implementation of risk management procedures and on monitoring compliance with established policies. The credit committee sets counterparty credit limits, monitors credit exposure levels and reviews compliance with established credit policies. Additionally, we employ a risk manager and a credit manager responsible for overseeing these functions.

Our risk management policies and procedures specify maximum price risk exposure levels within which each respective marketing company must operate. These policies and procedures establish relatively low exposure levels and prohibit speculative trading strategies.

As part of our enterprise-wide risk management strategy, we limit our exposure to energy marketing risks by maintaining separate credit facilities within each of our fuel marketing companies. These credit facilities have security interests solely against the assets of the respective marketing company, with the exception of a $1 million guarantee by our coal mining subsidiary on our coal marketing unit's credit facility. We do not currently issue parent company performance guarantees to counterparties of our marketing companies.

A significant 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 generation capabilities exceed our anticipated load requirements plus a required reserve margin. We further control this risk by selling only in the day-ahead power market and by entering into longer-term sales contracts that are made on a "unit contingent" basis, under which delivery is not required during unplanned outages at specified power plants.

California Markets

In 1996, California enacted legislation restructuring the state's investor-owned utilities. The legislation instituted a freeze on retail rates that investor-owned utilities could charge their customers for the duration of a transition period established by the legislation. The legislation did not make any provision for a California utility to recover costs of purchased electricity that exceeded the rates that could be charged under the rate freeze. Due to inadequate supplies of power and an unanticipated surge in demand, the California market has experienced rapid increases in electric power and natural gas prices. As a result, the state's two largest investor-owned utilities, Pacific Gas & Electric Company (PG&E) and Southern California Edison (SCE), have incurred costs of procuring power significantly in excess of their ability to recover those costs through authorized retail rates and have indicated that, unless the rate freeze is eliminated or other proposed relief is provided, they are, or shortly will become, insolvent.

We may experience losses related to the potential insolvency of the California utilities in the event that a utility defaults on its obligations:

- under its agreements with us;
- to the CAISO, which administers the real-time markets for energy and ancillary services, resulting in non-payment to us under our capacity sales agreement with the CAISO; or

- to other energy companies, causing those energy companies to default on their obligations to us.

We have two agreements with SCE involving our California independent power plants.

- In 1999, we entered into a settlement agreement with SCE involving the Harbor Cogeneration plant located in Wilmington, California, in which we own a 31.8 percent interest. The settlement agreement provides for the termination of a 30-year power purchase agreement, in exchange for payments of approximately $4 million per year by SCE through October 2008 for our interest in the plant.

- The cogeneration plant located in Ontario, California is entitled to receive energy and capacity payments from SCE of approximately $1.7 million per year, under a long-term contract expiring in 2010.

As of March 1, 2001, SCE owed us past due payments of approximately $1.5 million, with delinquencies ranging from 15 to 75 days in duration. We have no other material contractual relationships with SCE and no material agreements with PG&E.

The Harbor Cogeneration plant has sold the peaking capacity from its expansion to the CAISO for the peak summer periods of 2001 through 2003 under an agreement that provides for payments to us of $1 million per year for each of 2001, 2002 and 2003. We have no other agreements with the CAISO and do not otherwise sell capacity and energy directly into the California market either through long-term contracts or on a merchant basis. All other merchant sales are made to power marketers who in turn sell into the California market. In addition, our fuel production and fuel marketing exposure to the California market is primarily indirect through sales to creditworthy counterparties, including neighboring utilities and gas and power marketing firms.

In recent months, the Governor of the State of California, representatives of the state legislature and numerous industry participants have undertaken several initiatives designed to address market disruptions in California. In February 2001, SCE reached a tentative agreement under which the state would pay $2.76 billion to purchase SCE's high voltage transmission system and SCE would drop a federal lawsuit in which it has sought authority to bill its customers for past unrecovered costs. Prior to its implementation, this agreement must be approved by the California state legislature. There is no assurance that any legislation will be enacted or that, if enacted, the sale of transmission assets will provide SCE with sufficient funds to pay any current or future obligations to us. In addition, there is no assurance that any current or future defaults by California utilities on obligations owed to others will not result in defaults by our counterparties. However, we believe that our direct exposure to potential defaults in the California market is largely limited to the agreements with SCE and the CAISO described above and that our indirect exposure is minimal.

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 their requirements. We strive to comply with the terms of all such laws, regulations, permits and licenses and believe that all of our operating plans are in material compliance with all such applicable requirements.

Energy Regulation

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making 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. All of our subsidiaries that would otherwise be treated as public utilities are currently treated as EWGs under the Energy Policy Act. 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 the states. All of our EWGs to date that have sought rate approval from FERC 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, it would most likely be necessary to file, and obtain FERC acceptance of, cost-based rate schedules for any of our 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.

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.

Clean Air Act. Our Neil Simpson II and Wyodak plants located in Gillette, Wyoming are 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 the Neil Simpson II plant and our interest in the Wyodak plant through 2030 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 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.

On July 14, 2000, the South Coast Air Quality Management District, known as SCAQMD, sent a letter to our affiliate, now called Black Hills Ontario, L.L.C., the operator of a 12 megawatt natural-gas fired cogeneration facility located in Ontario, California, stating that the SCAQMD had determined, as a result of a facility audit completed for the compliance year ended June 1, 1999, that the facility's nitrogen oxide, or NOx, emissions were 28,958 pounds over the facility's NOx allocation established by the SCAQMD's RECLAIM emissions trading program. As a result, the SCAQMD indicated that it would be reducing the facility's NOx allocation by the same number of allowances for the compliance year subsequent to a final determination on this issue. If a final determination is reached prior to June 30, 2001, the NOx allowances would be deducted from the facility's allocation for the compliance year ended June 30, 2002. Black Hills Ontario has provided documentation to the SCAQMD disputing this proposed reduction. In addition to this proposed reduction, which could affect the facility's compliance with RECLAIM requirements for the 2001-2002 compliance period, Black Hills Ontario also projects that its NOx emissions for the compliance year ended June 30, 2001 may be approximately 30,000 pounds over its current NOx allocation. There is currently significant volatility in the price and supply of RECLAIM NOx allowances; although the 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, 2001, or, if allowances are available, as to the cost of those allowances. Black Hills Ontario may also be subject to administrative or civil penalties with respect to alleged violations of the SCAQMD's regulation for the compliance year ended June 30, 1999, although no notice of such penalties has been issued.

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. The submission of these plans is due between 2004 and 2008. In January 2001, the EPA proposed guidance to assist states in determining which sources should be subject to the BART requirement, but the proposed guidance has not been published pending a review by the newly appointed administrator of the EPA. If the proposed rules are adopted, management believes that the only existing plant which may be required to comply with Clean Air Act requirements is our Neil Simpson I plant and that any capital expenditures associated with bringing the plant into compliance would not have a material adverse effect on our financial condition or results of operations.

Title V of the Clean Air Act imposes federal requirements which dictate that all of our fossil fuel-fired generation facilities must obtain operating permits. All of our existing facilities subject to this requirement have submitted timely Title V permit applications and received 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 have 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, and also issued an administrative order to the Tennessee Valley Authority for similar violations at some of its power plants. 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. To date, we are aware of three large utilities that have either settled with the United States or have reached agreements in principle to resolve these actions. In each case, the settling party has agreed (or agreed in principle) to incur over $1 billion in expenditures for the installation of additional pollution control, the retirement or repowering of coal-fired generating units, supplemental environmental projects and civil penalties. 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 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. In March 2001, the Bush administration announced that it would not seek to impose any limitations on carbon dioxide emissions.

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. Two of these facilities are currently in the process of renewing their existing NPDES permits.

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, they can give no assurances 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 the federal or state government 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 all of our 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 currently estimate the cost of reclamation for our mine at approximately $26 million and have currently accrued approximately $17.7 million on our balance sheet for these reclamation costs. No assurance can be given that additional requirements in the future may 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 $472,000, of which amount $386,000 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.

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 consisting of approximately 47,000 square feet of office space in Rapid City, South Dakota. We occupy approximately 27,000 square feet in this building and lease the remainder to others.

Employees

At December 31, 2000, we had 635 employees, approximately 332 of whom are employed in our utility business, 170 of whom are employed in our independent energy businesses and 133 of whom are employed in our communications business.

Approximately one-half of our utility employees are covered by collective bargaining agreements with the International Brotherhood of Electrical Workers which expire on April 1, 2003. We have experienced no significant labor stoppages or labor disputes at our facilities.

ITEM 3. LEGAL PROCEEDINGS

PacifiCorp Litigation

In August 2000, we initiated an action in the United States District Court for the District of Wyoming against PacifiCorp relating to a coal supply agreement between PacifiCorp and us. We believe that PacifiCorp has failed to make complete payment to us for coal sold under the coal supply agreement and that PacifiCorp continues to underpay its monthly coal bill by approximately $100,000 per month. We believe that PacifiCorp's actions constitute a breach of the coal supply agreement and have asked for relief in the amount of $5.0 million, plus all underpayments since the commencement of our lawsuit.

PacifiCorp subsequently brought a counterclaim against us, alleging that we had not properly adjusted upward and downward the components which make up the coal price under the coal supply agreement, resulting in alleged overbilling to PacifiCorp of $35.0 million to $40.0 million over an undefined period. PacifiCorp further alleged that if past practices continue our adjustment methodology will result in additional overcharges of approximately $150.0 million through the balance of the term of the coal supply agreement, which expires in June 2013. In its counterclaim, PacifiCorp seeks to cancel and terminate the contract and to recover monetary damages as proven at trial.

Management believes that we have properly billed PacifiCorp under the terms of the coal supply agreement and that PacifiCorp's withholding of payment constitutes a breach of contract on their part. Although it is impossible to predict whether we will ultimately be successful with our claim or in defending PacifiCorp's claim or, if not successful, what the impact might be, management believes that the disposition of this matter will not have a material adverse effect on our consolidated results of operations or financial condition. In addition, management believes that the pending litigation has not affected and will not affect our other agreements with PacifiCorp.

Other Litigation

There are no other material legal proceedings pending, other than ordinary routine litigation incidental to our business, to which we are a party. There are no material legal proceedings to which an officer or director is a party or has a material interest adverse to us or our subsidiaries. There are 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 other than the SCAQMD RECLAIM requirements on the Ontario Facility "see ITEMS 1 AND 2. BUSINESS AND PROPERTIES - - Regulation - Environmental Regulation - Clean Air Act."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are a growth oriented, diversified energy holding company operating principally in the United States. Our regulated and unregulated businesses have expanded significantly in recent years. Our independent energy group produces and markets power and fuel. We produce and sell electricity in a number of markets, with a strong emphasis in the western United States. We also produce coal, natural gas and crude oil primarily in the Rocky Mountain region and market fuel products nationwide. We also own Black Hills Power, Inc., an electric utility serving approximately 58,600 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communications services to residential and business customers in Rapid City and the northern Black Hills region of South Dakota.

Results of Operations

Consolidated Results

Consolidated net income for 2000 was $52.8 million, compared to $37.1 million in 1999 and $25.8 million in 1998 or $2.37 per average common share in 2000, compared to $1.73 and $1.19 per average common share in 1999 and 1998, respectively. This equates to a 19.0 percent, 17.1 percent and 12.5 percent return on year-end common equity in 2000, 1999 and 1998, respectively.

We reported record earnings in 2000, 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 independent energy business group in 2000 were partially offset by start-up losses in our communications business. Unusual energy market conditions stemming primarily from gas and electricity shortages in California contributed to our strong financial performance in 2000. There was a $0.40 contribution to 2000 earnings per share due to prevailing prices of gas and electricity and unusually wide gas trading margins that may not recur in the future.

Earnings in 1999 increased over 1998 due primarily to sales growth in our electric utility and improved results in our independent energy business group, partially offset by expected start-up losses in our communications business.

In 1998, we recorded an $8.8 million (after tax) charge to earnings related to a write-down of certain oil and natural gas properties. Absent this charge, our earnings per average common share for 1998 would have been $1.60, and our return on year-end common equity would have been 16.1 percent. The write-down was primarily due to historically low crude oil prices, lower natural gas prices and a decline in value of certain unevaluated properties.

Consolidated revenues were $1,623.8 million, $791.9 million and $679.3 million in 2000, 1999 and 1998, respectively, representing a 105 percent increase in 2000 and a 17 percent increase in 1999.

The growth in revenues in 2000 was a result of high energy commodity prices and increased volumes of fuel marketed, primarily as a result of extreme price volatility in the western markets, acquisitions and growth in the independent energy business group and increases in off-system sales by our electric utility. Prices of natural gas marketed increased from an average of $1.97-$2.15 per million British thermal units in 1998 and 1999 to $4.19 per million British thermal units in 2000. Daily volumes of natural gas marketed increased 35 percent from 635,500 million British thermal units per day in 1999 to 860,800 million British thermal units in 2000.

Revenue increases in 1999 resulted primarily from the acquisitions and growth in the fuel marketing segment of our independent energy business group and off-system sales by our electric utility.

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

	2000	1999	1998
Revenue:			
Independent energy	89%	83%	81%
Electric utility	11	17	19
Communications	-	-	-
	100%	100%	100%
Net Income (Loss):			
Independent energy	55%	31%	5%
Electric utility	70	74	96
Communications	(25)	(5)	(1)
	100%	100%	100%

Net income from the independent energy group is expected to exceed net income derived from our utility in 2001. We expect that earnings growth from the independent energy group over the next few years will be driven primarily by our continued expansion in the independent power production segment. We also believe that continued strength in commodity prices and energy markets will provide the opportunity for strong results in our fuel marketing and oil and gas production operations.

Our electric utility has continued to produce modest growth in revenue and earnings from the retail business over the past two years. We believe that this trend is stable and that, absent unplanned system outages, it will continue for the next several years due to the extension of our electric utility's rate freeze until January 1, 2005. (See Rate Regulation.) The share of the utility's future earnings generated from wholesale off-system sales will depend on many factors, including native load growth, plant availability and commodity prices in the western markets.

Although our communications business significantly increased residential and business customers in 2000, we expect it will sustain approximately $10 million in net losses in 2001, with annual losses decreasing thereafter and profitability expected in the next three to four years.

The following business group and segment information includes intercompany eliminations.

Independent Energy

	2000	1999	1998
		(in thousands)	
Revenue:			
Fuel marketing	$1,353,795	$614,228	$506,043
Coal production	30,530	31,095	31,413
Oil and gas production	19,183	13,052	12,562
Independent power	39,331	-	-
Total revenue	1,442,839	658,375	550,018
Expenses	1,381,991	644,196	536,048*
Operating income	$ 60,848	$ 14,179	$ 13,970*
Net income	$ 28,946	$ 11,882	$ 10,068*
EBITDA	$ 65,184	$ 25,016	$ 22,530

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* Excludes $13.5 million pre-tax, $8.8 million after tax, non-cash write-down relating to oil and gas properties due to historically low crude oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

EBITDA represents earnings before interest, income taxes, depreciation and amortization and any non-recurring or non-cash items. EBITDA is used by management and some investors as an indicator of a company's historical ability to service debt. Management believes that an increase in EBITDA is an indicator of improved ability to service existing debt, to sustain potential future increases in debt and to satisfy capital requirements. However, EBITDA is not intended to represent cash flows for the period, nor has it been presented as an alternative to either operating income, or as an indicator of operating performance or cash flows from operating, investing and financing activities, as determined by generally accepted accounting principles. EBITDA as presented may not be comparable to other similarly titled measures of other companies.

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

	2000	1999	1998
Tons of coal sold	3,050,000	3,180,000	3,280,000
Barrels of oil sold	334,000	318,000	344,000
Mcf of natural gas sold	3,274,000	2,791,000	2,056,000
Mcf equivalent sales	5,278,000	4,698,000	4,120,000

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

	2000	1999	1998
Natural gas - MMBtus	860,800	635,500	524,800
Crude oil - barrels	44,300	19,270	19,000
Coal - tons	4,400	4,500	4,400*

* Since the acquisition date

The independent energy business group's revenues increased 119 percent in 2000 and 20 percent in 1999. The revenue increase in 2000 was a direct result of gas and electricity shortages in the West Coast markets and the closing of the Indeck Capital acquisition. The revenue increase in 1999 was primarily the result of consolidating our three fuel marketing companies' operations from the time of their acquisitions. Additionally, revenues increased in both years as a result of increased volumes and increased fuel and power prices. Daily volumes of natural gas marketed increased 35 percent in 2000 and 21 percent in 1999. The July 2000 acquisition of Indeck Capital contributed to our strong earnings growth in 2000. In addition, in December 2000, we sold our ownership interest in a power fund management company which resulted in a $3.7 million pre-tax gain.

The independent energy business group's total operating expenses, EBITDA and operating income increased over 115 percent, 160 percent and 329 percent, respectively, in 2000 compared to 1999. Net income of this group increased 144 percent in 2000. These increases resulted primarily from our gas marketing operations, which experienced a dramatic increase in both trading volumes and margins, a significant increase in fuel production volumes, record fuel and power prices and expanded power generation. The independent energy business group's 1999 net income improved over 1998 (excluding the non-cash charge in 1998) primarily due to record gas production, improved oil prices, lower depletion expense and the sale of certain retail gas marketing operations in 1999, partially offset by a non-cash write-down of certain intangible assets relating to our wholesale gas marketing office in Houston.

Coal Mining

Coal mining results were as follows:

	2000	1999	1998
		(in thousands)	
Revenue	$30,530	$31,095	$31,413
Operating income	8,800	12,600	12,700
Net income	7,200	9,700	9,750
EBITDA	19,000	15,700	15,600

A planned five-week overhaul of the Wyodak plant resulted in lower coal sales and earnings in 2000 compared to 1999 and 1998.

Oil and Gas

Oil and gas operating results were as follows:

	2000	1999	1998
		(in thousands)	
Revenue	$19,183	$13,052	$ 12,562
Operating income	7,900	4,000	1,200*
Net income	5,000	2,500	800*
EBITDA	11,900	6,900	6,400

*Excludes the impact of a $13.5 million pre-tax, $8.8 million after tax, non-cash write-down relating to oil and gas properties due to historically low crude oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

Record net income in 2000 was primarily a result of record natural gas prices, higher crude oil prices, and a significant increase in production volumes. Operating results for 1998 decreased primarily as a result of historically low crude oil prices, which not only reduced revenue but also increased depletion expense (lower oil and gas prices reduce the economically recoverable reserve amounts, causing an increase in depletion expense). We recognized approximately $3.7 million, $2.6 million and $4.9 million of depletion expense (excluding the write-down in 1998) related to gas and oil production in 2000, 1999 and 1998, respectively.

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

	2000	1999	1998
Barrels of oil (in millions)	4.41	4.11	2.37
Bcf of natural gas	18.4	19.5	16.0
Total in Bcf equivalents	44.88	44.11	30.16

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. The increase in oil reserves at December 31, 2000 was due to improved product prices. The increase in reserves at December 31, 1999 was due to strong drilling results, reserve acquisitions and improved product prices. We intend to increase our net proved reserves by selectively increasing our oil and gas exploration and development activities and by acquiring producing properties.

Fuel Marketing

Our fuel marketing companies produced the following results:

	2000	1999	1998
	(in thousands)		
Revenue	$1,353,795	$614,228	$506,043
Operating income (loss)	23,800	(2,200)	-
Net income	14,000	(200)	(300)
EBITDA	23,700	2,500	600

Record volumes marketed and strong margins contributed to the increase in net income from fuel marketing in 2000 compared to 1999 and 1998. During 1999, the fuel marketing companies sold certain of their retail gas marketing operations, resulting in after-tax gains of approximately $1.8 million. In 1999, revenue and the related cost of sales increased primarily due to a full year of coal marketing operations (acquired in September 1998), increased product prices and increased oil volumes marketed. Operating income in 1999 was reduced by a non-cash write-down of certain intangible assets relating to the wholesale gas marketing office in Houston in the amount of approximately $1.2 million (after tax).

Our fuel marketing companies generate large amounts of revenue and corresponding expense related to buying and selling energy commodities. Fuel marketing is extremely competitive, and margins are typically very small. The unusual energy market conditions stemming primarily from natural gas and electricity shortages in California contributed to the strong financial performance in 2000 and may not recur in the future. However, we believe that the continued growth of our fuel and power production businesses will create opportunities for us to continue to generate strong fuel marketing operating results in future years.

Independent Power Production

Our independent power segment produced the following results:

	2000	1999	1998
	(in thousands)		
Revenue	$39,331	$ -	$ -
Operating income (loss)	20,400	(160)	(160)
Net income	3,200	(110)	(120)
EBITDA	10,751	(160)	(160)

Results from the independent power production segment were not significant either in 1999 or 1998. In July 2000, we completed the acquisition of Indeck Capital, representing a significant advancement of our position in the independent power production segment. We now own 250 net megawatts in currently operating plants. Of this 250 net megawatts, approximately 179 megawatts is under contracts or tolling arrangements with at least one year remaining; approximately 40 megawatts is owned through minority interests in independent power investment funds which we do not manage, and the remainder is sold under short-term market arrangements. An additional 470 megawatts of generating capacity is currently under construction. We expect to sell substantially all of this output under long-term contracts. We expect to increase revenues and earnings in this segment beyond 2001 through future project development.

Electric Utility

	2000	1999	1998
		(in thousands)	
Revenue	$173,308	$133,222	$129,236
Operating expenses	105,100	80,936	79,340
Operating income	$ 68,208	$ 52,286	$ 49,896
Net income	$ 37,105	$ 27,286	$ 24,825
EBITDA	$ 88,853	$ 68,299	$ 64,936

Electric revenue increased 30.1 percent in 2000 compared to 3.1 percent in 1999. The increase in electric revenue in 2000 was primarily due to a 54 percent increase in wholesale off-system sales at an average price that was 3.1 times higher than the average price in 1999. The increase in off-system sales was driven by high spot market prices for energy in 2000, 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. Megawatthours generated from our oil-fired diesel and natural gas-fired combustion turbines were 305,767 in 2000, 25,882 in 1999 and 33,082 in 1998. 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 kilowatthour sales increased 2.8 percent in 2000 compared to a decrease of 0.1 percent in 1999. Residential and commercial sales increases of 6 percent and 3 percent, respectively, in 2000 were partially offset by a 2 percent decrease in industrial sales, primarily due to load reductions at Homestake Gold Mine. Degree days, a measure of weather trends, were 16 percent above 1999 and 1 percent above normal in 2000. Degree days in 1999 were 9 percent below 1998 and 13 percent below normal. The increase in electric revenue in 1999 was primarily due to stable firm sales combined with a 20 percent increase in off-system sales.

Revenue per kilowatthour sold was 6.4 cents in 2000 compared to 5.4 cents in 1999 and 1998. The number of customers in the service area increased to 58,601 from 57,709 in 1999 and from 56,856 in 1998. The revenue per kilowatthour sold in 2000 reflects a 54 percent increase in wholesale non-firm sales to 684,378 megawatthours and robust wholesale power prices. The revenue per kilowatthour sold in 1999 reflects the 20 percent increase in wholesale non-firm sales to 445,712 megawatthours. The revenue per kilowatthour sold in 1998 reflects the 33 percent increase in wholesale non-firm sales to 371,104 megawatthours.

Electric utility operating expenses increased by 30 percent in 2000 primarily due to increased fuel, purchased power, and operating and maintenance expenses, partially offset by lower depreciation. Fuel expense in 2000 included the cost associated with the additional combustion turbine generation. Operating expenses increased 2.0 percent in 1999, primarily due to increased purchase power expense, operations and maintenance expenses and depreciation, partially offset by lower fuel expense.

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 1 percent, with the system demand forecasted to increase at a rate of 2 percent. We currently have a winter peak of 344 megawatts established in December 1998 and a summer peak of 372 megawatts established in August 2000. 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.

Communications

	2000	1999	1998
		(in thousands)	
Revenue	$ 7,689	$ 278	$ -
Operating expenses	20,175	4,852	1,087
Operating loss	$(12,486)	$(4,574)	$(1,087)
Net loss	$(12,027)	$(1,262)	$ (280)
EBITDA	$(13,144)	$(2,626)	$ (570)

In September 1998, we formed our communications business to provide facilities-based communications services for Rapid City and the northern Black Hills of South Dakota. We have invested more than $100 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. The build-out is approximately 75 percent complete and is expected to be completed in 2001. Further capital expenditures of approximately $31.3 million are expected over the next two years to complete the build-out of the fiber optic network and to acquire customer premise equipment for sale to customers.

We began serving communications customers in late 1999 and market our services to schools, hospitals, cities, economic development groups, and business and residential customers. Operating losses in 2000 were attributable to increased interest, depreciation and operating expenses. Operating losses in 1999 were primarily due to start-up organizational costs, increased depreciation expense and increased interest expense associated with the capital deployment. As of December 31, 2000, we had 8,368 residential customers and 646 business customers. We expect to more than double the number of customers in 2001. Our goal is to attain 50 percent residential penetration while serving 35 percent of all broadband business customers within our service territory. If we are unable to attract additional customers or technological advances make our network obsolete, we could have a write-down of our assets which could be material.

Liquidity and Capital Resources

In 2000, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common stock and to pay long-term debt maturities. We funded property additions primarily related to construction of additional electric generation facilities for our independent energy business group through a combination of operating cash flow, increased short-term debt and long-term non-recourse project financing. Investing and financing activities increased primarily as a result of the acquisition of Indeck Capital in July 2000 and construction of several generating facilities. Cash flows from operations increased $0.7 million, primarily due to increased net income and depreciation partially offset by increased working capital. We expect increased operating cash flows resulting from our investing activities to support the additional indebtedness.

As part of our acquisition of Indeck Capital, we incurred $40.3 million of additional debt through an increase in borrowings on our short-term credit facilities, which were used to repay certain obligations of Indeck Capital. In addition, we issued 1.537 million shares of common stock and 4,000 shares of convertible preferred stock to the former Indeck Capital shareholders.

In 1999, we generated cash from operations sufficient to meet our operating needs, to pay dividends on our common stock, to pay long-term debt maturities and to provide financing for our investment in independent power assets. Property additions were primarily financed through increased short-term debt and notes payable. Cash flows from operations increased $19 million primarily due to increased net income and decreased working capital. Cash flows from investing activities increased substantially, primarily related to the deployment of our fiber optic communications network and our investment in the construction of generating facilities. Cash flows from financing activities increased primarily due to increased short-term indebtedness to fund our investing activities.

In the past, we have relied upon internally generated funds and the issuance of short- and long-term debt to finance our activities. We expect that an appropriate mix of financing options will be used to finance future activities.

Dividends paid on our common stock totaled $1.08 per share in 2000. This reflected increases approved by our board of directors from $1.04 per share in 1999 and $1.00 per share in 1998. All dividends were paid out of current earnings. Our three-year annual dividend growth rate was 4.4 percent and our payout ratio for 2000 was 45 percent. In January 2001, our board of directors increased the quarterly dividend 3.7 percent to 28 cents per share. If this dividend is maintained during 2001, it will be equivalent to $1.12 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.

Capital Requirements

Our primary capital requirements for the three years ended December 31, 2000 were as follows:

	2000	1999	1998
		(in thousands)	
Property and investment additions:			
Independent energy	$130,787	$73,656	$12,040
Electric utility	25,257	31,911	11,451
Communications and other	58,922	49,042	1,774
Common stock dividends	23,527	22,602	21,737
Fuel marketing assets	-	-	1,960
Maturities/redemptions of long-term debt	1,330	1,330	1,331
	$239,823	$178,541	$50,293

Our capital additions for 2000 were $215 million. The major capital items for the year included the following: acquisition of the net assets of Indeck Capital; completion of construction of the 80 megawatt gas-fired generation units at the Arapahoe site in Denver, Colorado, which we placed in service in May 2000; completion of construction of the 40 megawatt gas-fired Valmont combustion turbine unit located in Boulder, Colorado, which we placed in service in May 2000; acquisitions of various interests in partnerships in which we previously held a minority interest; completion of construction of the 40 megawatt gas-fired Neil Simpson combustion turbine unit at our Wyodak site, which we placed in service in June 2000; and the construction of our communications fiber optic network.

Forecasted capital requirements for projected plant construction, other independent energy investments, regulated utility capital improvements and completion of the communications network are as follows:

	2001	2002	2003
		(in thousands)	
Independent energy	$ 287,200	$ 208,390	$ 195,540
Electric utility	18,340	18,160	16,450
Communications	25,390	5,920	3,290
	$ 330,930	$ 232,470	$ 215,280

Our independent energy business group's forecasted capital requirements include the following:

- Acquisition of a 240 megawatt Fountain Valley gas-fired turbine generation facility currently under construction, located near Colorado Springs, Colorado. Construction is expected to be completed in 2001, with an expected cost of approximately $175 million.

- Completion of construction of a 40 megawatt gas-fired combustion turbine at our Wyodak, Wyoming site (expected in mid-2001).

- Completion of construction of a 40 megawatt gas-turbine expansion at our Valmont, Colorado site (expected in mid-2001).

- Completion of construction of a 50 megawatt combined-cycle expansion at our Arapahoe, Colorado site (expected in mid-2002).

- Expansion of the Harbor Cogeneration plant in Wilmington, California with a 30 megawatt combined-cycle upgrade. This expansion is currently in development, with anticipated completion in the second quarter of 2001. We have a 31.8 percent financial interest in this project.

- Acquisition of operating and non-operating interests in 74 gas and oil wells from Stewart Petroleum Corporation, which is expected to be completed in April 2001.

- Construction of a 40 megawatt gas-fired turbine known as the Lange project (expected in mid-2002).

- Expected development of an additional 400 megawatts of generating capacity in years 2002-2003.

We expect to finance our independent energy business group's purchase and construction of electric 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 I plant, a 90 megawatt coal-fired plant under construction at our Wyodak, Wyoming site. Because of the leasing arrangement, the $130 million total construction costs of the plant are not included in the above three-year capital expenditure forecast. Wygen I will be 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. We anticipate that the Wygen I plant will be operational by March of 2003.

Forecasted capital expenditures for our electric utility operations include new 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. We do not expect additional generation capacity to be added to our utility over the forecast period.

Our communications group's capital requirements forecast primarily consists of 2001 costs related to the completion of our fiber optic network in Rapid City and the northern Black Hills of South Dakota. We expect construction to be substantially completed by November 2001, with forecasted capital expenditures thereafter consisting of capital improvements to the then existing network infrastructure.

Lines of Credit

We have lines of credit with various banks totaling $290 million at December 31, 2000 and $115 million at December 31, 1999, which are currently available to support bank borrowings or to provide for letters of credit. There were $211 million of borrowings and $20.6 million of letters of credit issued under these lines of credit at December 31, 2000, and $96.6 million of borrowings and no letters of credit issued at December 31, 1999. We had no compensating balance requirements associated with these lines of credit. The lines of credit are subject to periodic review and renewal during the year by the banks.

In addition, Enserco Energy, Inc., our gas marketing unit, has a $90 million uncommitted, discretionary line of credit to provide support for the purchase of natural gas. We provide no guarantee to the lender under this facility. At December 31, 2000 and 1999, there were outstanding letters of credit issued under the facility of $69.8 million and $19.9 million, respectively, with no borrowing balances on the facility.

Similarly, Black Hills Energy Resources, Inc., our oil marketing unit, has a $25 million uncommitted, discretionary credit facility. This line of credit provides credit support for the purchases of crude oil by Black Hills Energy Resources. We provide no guarantee to the lender under this facility. At December 31, 2000 and 1999, Black Hills Energy Resources had letters of credit outstanding of $8.5 million and $13.2 million, respectively, and no balance outstanding on its overdraft line.

Coal Reclamation Reserves

Under our 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. Approximately $0.7 million is charged to operations as reclamation expense annually. As of December 31, 2000, accrued reclamation costs were approximately $17.7 million.

Long-term Debt/Credit Ratings

The long-term debt component of our capital structure at December 31, 2000 and 1999 was 52 percent and 43 percent, respectively. With expected growth within the independent energy business group, we anticipate our long-term debt ratio will increase to 55-60 percent in the next five years.

Our utility's first mortgage bonds are rated "A1" by Moody's Investors Service, Inc. and "A+" by Standard & Poor's Ratings Services. These ratings reflect the respective agencies' opinions of the credit quality of our utility and the security underlying the first mortgage bonds.

Market Risk Disclosures

Price Risk Management

Our operations are exposed to market risk arising from changes in commodity prices. These changes could cause fluctuations in our earnings and cash flows. In the normal course of business, we actively manage our exposure to these market risks by entering into various hedging transactions. Hedging transactions involve the use of a variety of derivative financial instruments. Our risk management policies place clear controls on these activities.

We have adopted risk management policies and procedures, approved by our board of directors, and reviewed routinely by the audit committee of the board of directors. Our risk management policies and procedures include, but are not limited to, risk tolerance levels relating to authorized derivative financial instruments, position limits, authorization of transactions and credit exposure.

Operating margins earned by wholesale gas and crude oil marketing are relatively insensitive to commodity price fluctuations since most of the purchase and sales contracts do not contain fixed-price provisions. Generally, prices contained in these contracts are tied to a current spot or index price and, therefore, adjust directionally with changes in overall market conditions. We generally attempt to balance our fixed-price physical and financial purchase and sales commitments. However, we may at times have a bias in the market, within established guidelines, resulting from the management of our portfolio. To the extent a net open position exists, fluctuating commodity market prices can impact our financial position or results of operations, either favorably or unfavorably. The net open positions are actively managed, and the impact of changing prices on our financial condition at a point in time is not necessarily indicative of the impact of price movements throughout the year.

Effective January 1, 1999, we adopted the provisions of Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10). The resulting effect of adoption of the provisions of EITF 98-10 was to alter our comprehensive method of accounting for energy-related contracts, as defined in that statement.

We account for all energy trading activities at fair value as of the balance sheet date and recognize currently the net gains or losses resulting from the revaluation of these contracts to fair value in our results of operations. As a result, substantially all of the energy trading activities of our gas marketing, crude oil marketing and coal marketing operations are accounted for under fair value accounting methodology as prescribed in EITF 98-10.

Through our independent energy business group, we utilize financial instruments for our fuel marketing services. These financial instruments include fixed-for-float swap financial instruments, basis swap financial instruments, and costless collars traded in the over-the-counter financial markets.

The derivatives are not held for speculative purposes but rather serve to hedge our exposure related to commodity purchases or sales commitments. Under EITF 98-10, these transactions qualify as energy trading activities that must be accounted for at fair value. As such, realized and unrealized gains and losses are recorded as a component of income. Because we do not speculate with "open" positions, substantially all of our trading activities are back-to-back positions where a commitment to buy/(sell) a commodity is matched with a committed sale/(buy) or financial instrument. The quantities and maximum terms of derivative financial instruments held for trading purposes at December 31, 2000 and 1999 are as follows:

December 31, 2000	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas basis swaps purchased	25,577,894	2
Natural gas basis swaps sold	26,059,621	2
Natural gas fixed-for-float swaps purchased	6,476,222	1
Natural gas fixed-for-float swaps sold	7,360,560	1
(Tons)		
Coal tons sold	988,000	1
Coal tons purchased	896,000	1

December 31, 1999	Volume Covered	Max. Term (Years)
(MMBtus)		
Natural gas futures contracts purchased	860,000	1
Natural gas basis swaps purchased	17,741,500	4
Natural gas basis swaps sold	18,390,517	4
Natural gas fixed-for-float swaps purchased	9,490,486	1
Natural gas fixed-for-float swaps sold	10,994,521	1
Natural gas collar transactions; puts purchased, calls sold	408,500	1
Natural gas collar transactions; calls purchased, puts sold	318,500	1

As required under EITF 98-10, energy trading activities were marked to fair value on December 31, 2000, and the gains and losses recognized in earnings. The entries for the accompanying consolidated balance sheets and income statement are as follows (in thousands):

Instrument	Asset	Liability	Gain (loss)
Natural gas basis swaps	$13,391	$23,963	$(10,572)
Natural gas fixed-for-float swaps	24,617	27,110	(2,493)
Natural gas physical	23,391	9,427	13,964
Coal transactions	5,370	4,460	910
Crude oil transactions	1,523	1,000	523
Totals	$68,292	$65,960	$ 2,332

There were no significant differences between the fair values of derivative assets and liabilities at December 31, 1999.

Non-trading Energy Activities

To reduce risk from fluctuations in the price of oil and natural gas, we enter into swaps and costless collar transactions. We use these transactions to hedge price risk from sales of our forecasted crude oil and natural gas production. For such transactions, we utilize hedge accounting.

At December 31, 2000, we had fixed-for-float swaps for 17,000 barrels of oil per month for the year 2001 to hedge our crude oil price risk with a fair value of $34,000. We had fixed-for-float swaps for 10,000 barrels of oil per month for the year 2002 to hedge our crude oil price risk with a fair value of $416,000. We also had costless collars (purchased puts-sold calls) for 10,000 barrels of oil per month for 2001 with a fair value of $323,000. We hedged our forecasted 2001 natural gas production with fixed-for-float swaps. We had fixed-for-float swaps for 1,581,000 million British thermal units with a fair value of $(3.4) million. These amounts are not reflected in our December 31, 2000 consolidated balance sheet, but will be recorded as part of the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," on January 1, 2001.

Financing Activities

To reduce risk from fluctuations in interest rates, we enter into interest rate swap transactions. We use these transactions to hedge interest rate risk for variable rate debt financing. For such transactions, we utilize hedge accounting. At December 31, 2000, we had interest rate swaps with a notional amount of $127.4 million, which have a maximum term of six years and a fair value of $(7.5) million. These amounts are not reflected in our December 31, 2000 consolidated balance sheet, but will be recorded as part of the adoption of SFAS No. 133 on January 1, 2001.

Credit Risk

In addition to the risk associated with price movements, credit risk is also inherent in our risk management activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. While we have not experienced significant losses due to the credit risk associated with these arrangements, we have off-balance sheet risk to the extent that the counterparties to these transactions fail to perform as required by the terms of their contracts.

Interest Rate Risk

Our exposure to market risk for changes in interest rates relates primarily to our short-term investments and long-term debt obligations. As stated in our policy, we are averse to principal loss and ensure the safety and preservation of our investments by limiting default risk, market risk and reinvestment risk.

We mitigate default risk on short-term investments by investing in high credit quality securities consisting primarily of tax-exempt federal, state and local agency obligations, by periodically monitoring the credit rating of any investment issuer or guarantor and by limiting the amount of exposure to any one issuer. Our portfolio includes only securities with active secondary or resale markets to ensure portfolio liquidity. All short-term investments mature, by policy, in two years or less. The effect of a 100 basis point (1 percent) increase in interest rates would not have a material effect to our results of operations or financial condition, due to the short-term duration of the investment portfolio.

At December 31, 2000, we had $162.2 million of outstanding floating rate debt of which $34.8 million was not offset with interest rate swap transactions that effectively convert the interest on that debt to a fixed rate.

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).

	2001	2002	2003	2004	2005	Thereafter	Total
Cash equivalents							
Fixed rate	$ 24,913	$ -	$ -	$ -	$ -	$ -	$ 24,913
Average interest rate	6.23%	-	-	-	-	-	6.23%
Long-term debt							
Fixed rate	$ 3,070	$ 18,065	$ 3,122	$ 2,017	$ 2,026	$ 130,602	$ 158,902
Average interest rate	9.30%	6.98%	9.31%	9.50%	9.52%	8.30%	8.22%
Variable rate	$ 10,890	$ 11,919	$ 12,968	$ 14,380	$ 15,560	$ 96,433	$ 162,150
Average interest rate	8.20%	8.20%	8.19%	8.19%	8.19%	8.10%	8.14%
Total long-term debt	$ 13,960	$ 29,984	$ 16,090	$ 16,397	$ 17,586	$ 227,035	$ 321,052
Average interest rate	8.44%	7.46%	8.41%	8.35%	8.35%	8.22%	8.18%

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 is 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 three years we have initiated an effort to enter into new contracts with our largest industrial customers. The new contracts contain "meet or release" provisions which grant us a five-year right to continue to serve a customer at market rates in the event of deregulation. Additionally, through our new 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 116 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 48 percent of our utility's firm load.

Regulatory Accounting

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 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 would 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.

Business Outlook Statements

Business Strategy

Our strategy is to build long-term shareholder value by deploying our development, operating and marketing expertise in the energy industry. We plan to operate a mix of unregulated independent energy and regulated utility businesses, with emphasis on independent power generation and fuel production segments.

Our strategy includes the following key elements:

- grow our independent power segment by developing and acquiring power projects primarily in the western United States;
- expand the generating capacity of our existing sites through a strategy known as "brownfield development;"
- sell a large percentage of the production from our independent power projects through long-term contracts in order to secure attractive investment returns;
- increase our reserves of natural gas and expand our coal production;
- exploit our fuel cost advantages and our operating and marketing expertise to remain a low-cost power producer;
- exploit our knowledge and market expertise while managing the risk inherent in fuel marketing;
- build and maintain strong relationships with wholesale energy customers; and
- capitalize on our utility's established market presence, relationships and customer loyalty.

Future Communications Activities

Our communications operations are expected to have operating losses for the next three to four years. The recovery of capital investment and future profitability are dependent primarily on our ability to attract new customers, including customers from incumbent providers such as Qwest Communications and Midcontinent Communications, the incumbent telephone and cable television providers. Although we do not anticipate being regulated in the local markets we are unable to predict future markets, future government impositions and future economic conditions that could affect the profitability of the communications and technology operations.

Recent Developments and Acquisitions

In March 2001, we signed a definitive agreement to acquire a 240 megawatt gas-fired turbine generation facility located near Colorado Springs, Colorado from Enron Corporation. The transaction is expected to close around March 31, 2001.

The Fountain Valley facility features six LM-6000 simple-cycle, gas-fired turbines, a technology identical to our existing facilities in Colorado and Wyoming. All necessary permitting has been approved and the plant is expected to phase in its generation capacity beginning in June 2001. We also announced that we obtained an 11-year contract with Public Service of Colorado to utilize the plant for peaking purposes. The contract is a tolling arrangement in which we assume no fuel costs. The cost of the project is expected to be approximately $175 million. We expect to finance the project primarily with non-recourse project level debt, and negotiations are presently under way with certain lenders.

Risks and Uncertainties

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (Reform Act), we are hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected in forward-looking statements (as such term is defined in the Reform Act) made by or on behalf of the Company in our Annual Report on Form 10-K, Annual Report, Quarterly Report on Form 10-Q, and presentations, or in response to questions or otherwise. These statements concern our plans, expectations and objectives for future operations. All statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. The words "anticipate," "believe," "estimate," "expect," "intend," "plan," "predicts," "project," "will likely result," "will continue," or similar expressions are not statements of historical fact and may be forward-looking. These forward-looking statements include, among others, such things as:

- expansion and growth of our business and operations
- future financial performance;
- future acquisition and development of power plants;
- future production of coal, oil and natural gas;
- reserve estimates; and
- business strategy.

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 which could cause actual results to differ materially from those contained in the forward-looking statements, including the following factors:

- 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 resale competition;

- changes in and compliance with environmental and safety laws and policies;

- weather conditions;

- population growth and demographic patterns;

- competition for retail and wholesale customers;
- pricing and transportation of commodities;
- 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;
- capital market conditions;
- credit-worthiness of counterparties;
- technological advances;
- competition for new energy development opportunities; and
- legal and administrative proceedings that influence our business and profitability.

Any forward-looking statement speaks only as to the date on which that statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of an anticipated event. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

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

Dated: April 3, 2001