Filed Pursuant to Rule 424(b)(4)
Registration No. 333-57440

3,000,000 Shares

[LOGO]

Common Stock

We are selling 3,000,000 shares of common stock.

Our common stock is listed on The New York Stock Exchange under the symbol "BKH." The last reported sale price on April 18, 2001, was $53.21 per share.

The underwriters have an option to purchase a maximum of 450,000 additional shares to cover over-allotments of shares.

INVESTING IN THE COMMON STOCK INVOLVES RISKS. SEE "RISK FACTORS" ON PAGE 8.

	Price to Public	Underwriting Discounts and Commissions	Proceeds to Us
Per Share	$52.00	$2.86	$49.14
Total	$156,000,000	$8,580,000	$147,420,000

Delivery of the shares of common stock will be made on or about April 24, 2001.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

CREDIT SUISSE FIRST BOSTON — LEHMAN BROTHERS

CIBC WORLD MARKETS — UBS WARBURG

The date of this prospectus is April 18, 2001.

[Logo]
Black Hills Corporation

[Map of location of our assets]

[Picture of power generation project under construction and list of our projects under construction and early development]

[Picture of hydro plant and list of our plants]

[Picture of gas-fired power plant and list of our plants]

[Picture of coal power plant and list of our coal and other power plants]

[Picture of fuel marketing operations and list of our locations]

[Picture of oil and gas well and list of our operations]

[Picture of coal mine and list of our operations]

[Picture of communications facility and list of our operations]

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YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED IN THIS PROSPECTUS OR TO WHICH WE HAVE REFERRED YOU. WE HAVE NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH INFORMATION THAT IS DIFFERENT. THIS PROSPECTUS MAY ONLY BE USED WHERE IT IS LEGAL TO SELL THESE SECURITIES. THE INFORMATION IN THIS PROSPECTUS MAY ONLY BE ACCURATE ON THE DATE OF THIS DOCUMENT.

FORWARD-LOOKING STATEMENTS

This prospectus 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 prospectus 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," "goal," "aim," "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 as well as those factors discussed under the section of this prospectus entitled "Risk 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.

SUMMARY

THIS SUMMARY HIGHLIGHTS INFORMATION CONTAINED ELSEWHERE IN THIS PROSPECTUS AND MAY NOT CONTAIN ALL OF THE INFORMATION THAT IS IMPORTANT TO YOU. YOU SHOULD CAREFULLY READ THE MORE DETAILED INFORMATION IN THE REST OF THIS PROSPECTUS ABOUT US AND THE COMMON STOCK BEING SOLD IN THIS OFFERING, INCLUDING "RISK FACTORS," AND OUR CONSOLIDATED FINANCIAL STATEMENTS AND RELATED NOTES. UNLESS THE CONTEXT OTHERWISE REQUIRES, REFERENCES IN THIS PROSPECTUS TO "BLACK HILLS," "WE," "US" AND "OUR" REFER TO BLACK HILLS CORPORATION AND ALL OF ITS SUBSIDIARIES COLLECTIVELY.

ABOUT BLACK HILLS CORPORATION

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 unit 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.

INDEPENDENT ENERGY

In recent years, the independent energy group has been our primary source of revenue and net income growth. Net income from this group is expected to exceed net income derived from our regulated utility beginning in 2001.

Our independent power unit acquires, develops and operates unregulated power plants, primarily in the Rocky Mountain region of the United States. In July 2000, we expanded our presence in the independent power business by acquiring Indeck Capital, Inc. This acquisition and subsequent additions provide us with varying interests in 13 operating gas-fired and hydroelectric power plants in California, Colorado, Massachusetts and New York, of which we operate 12, as well as minority interests in several power-related funds. We have a total ownership interest of approximately 250 net megawatts. We are in the process of acquiring or constructing an additional net ownership interest of approximately 470 megawatts of generation capacity, approximately 330 megawatts of which we expect to be brought into service in 2001.

As of December 31, 2000, we had 275 million tons of low-sulfur sub-bituminous coal reserves at our Wyodak mine located near Gillette, Wyoming. Substantially all of our coal production is sold under long-term contracts with our electric utility and with PacifiCorp. Our Wyodak mine will also provide coal to a 90 megawatt mine-mouth power plant which is being developed for our independent power unit and is scheduled for completion in 2003. We recently announced that we have initiated the planning and permitting process for a 500 megawatt coal-fired mine mouth power plant at the Wyodak site that may be operational by 2005. Our oil and gas exploration and production unit owns and operates 324 oil and gas wells located in Wyoming and Colorado, and owns working interests in another 389 wells operated by others located in California, Montana, North Dakota, Texas, Wyoming, Colorado, Louisiana, Oklahoma and offshore in the Gulf of Mexico. 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% of our current production consisting of natural gas.

Our fuel marketing and transportation unit supplies wholesale natural gas marketing and risk management products and services primarily to customers in the Rocky Mountain and West Coast regions of the United States. In addition, this unit markets oil in the south and coal in the eastern and midwestern regions of the United States. Our customers include natural gas distribution companies, municipalities, industrial users, oil and gas producers, electric utilities and coal mines. Our average daily marketing volumes for the twelve months ended December 31, 2000 were approximately 860,800 million British thermal units of natural gas, 44,300 barrels of oil and 4,400 tons of coal. Our power marketing activities involve marketing of capacity and energy from our existing power generation facilities.

ELECTRIC UTILITY

Our electric utility engages in the generation, transmission and distribution of electricity to approximately 58,600 customers in South Dakota, Wyoming and Montana. We control 458 megawatts of generating capacity, including 65 megawatts of capacity purchased from others under long-term power contracts at rates which currently are significantly lower than prevailing market prices. Approximately 53% of our utility's generating capacity consists of coal-fired plants and 33% is gas- or oil-fired, with the remaining 14% purchased from others.

Our revenue mix for 2000 was comprised of 29% wholesale off-system, 26% commercial, 20% residential, 14% industrial, 10% contract wholesale and 1% municipal sales. In 2000, our South Dakota customers accounted for 92% of our retail electric revenues. Our retail electric rates in South Dakota are subject to a five-year freeze expiring on January 1, 2005. Because our generation capacity typically exceeds our peak load demands, we rarely purchase power on the spot market during periods of peak usage, permitting us to preserve our low-cost rate structure for our retail customers. Off-system sales offer a means to optimize the utilization of our power supply sources by permitting us to sell capacity and energy in excess of our native load requirements to wholesale customers at market prices which sometimes exceed our regulated retail rates. Wholesale off-system sales have represented an increasing percentage of our total revenues and net income. We added 40 megawatts of additional capacity to our system with the addition of the Neil Simpson combustion turbine, which we placed into operation in June 2000.

Our utility operates a transmission system of 447 miles of high voltage and 541 miles of lower voltage lines. Our system has the capability of connecting to either the midwestern or western transmission grids. This provides us with an important strategic opportunity to shift off-system power to areas of higher demand and profitability as market conditions warrant.

COMMUNICATIONS

Our communications group, known as Black Hills FiberCom, offers a full suite of local and long distance telephone service, expanded cable television service, cable modem Internet access and high-speed data and video services to residential and business customers. We have completed a 210 mile inter- and intra-city fiber optic network and currently operate nearly 600 miles of two-way interactive hybrid fiber coaxial cable in Rapid City and the northern Black Hills region of South Dakota. The construction of our communications network is approximately 75% complete, and we expect to substantially complete construction in 2001.

Since launching our services in November 1999, we have attracted over 9,000 residential and business customers. Our goal is to double the number of our customers and to attain 50% residential market penetration within our service territory while serving 35% of all broadband business customers in that territory. Our marketing strategy centers on providing bundled telecommunications services at competitive prices to commercial and residential customers. By bundling high speed Internet access with cable television and telephone service, we are able to exploit economies of scale and scope to offer customers relatively low-cost telecommunications solutions. Approximately 80% of our residential customers have opted for bundled services to date.

OUR 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.

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 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.

For more details about our business strategy, see "Business--Strategy."

RECENT DEVELOPMENTS

ESTIMATED EARNINGS FOR FIRST QUARTER OF 2001

Although our results of operations for the first quarter of 2001 are not currently available, the following information reflects our expectations with respect to these results based on currently available information. We expect our earnings for the first quarter of 2001 to reach record levels of approximately $1.30 to $1.35 per share, compared to $0.42 per share reported for the same quarter of 2000. The anticipated higher earnings in the first quarter of 2001 are primarily due to the continued strong performance of our wholesale gas marketing business and increased wholesale electric sales. We also expect earnings for our independent energy business group to exceed our electric utility's earnings for the first quarter of 2001. A portion of the increased earnings is attributable to continued unusual conditions in western gas and electricity markets. We also expect that our communications business group will report continued losses in the first quarter due to capital costs and related financing costs. We expect to report our first quarter financial results on or about May 4, 2001.

SETTLEMENT AGREEMENT

In April 2001, we entered into a settlement agreement with PacifiCorp whereby ongoing litigation between the parties related to coal sales by our subsidiary, Wyodak Resources, for PacifiCorp's Wyodak power plant has been withdrawn. For a description of the litigation, see "Business--Legal Proceedings."

A new coal supply contract for the Wyodak plant and other agreements were executed as a result of the settlement. The new coal supply contract for the Wyodak plant extends the term of the prior contract from 2013 to 2022. Wyodak Resources will receive a lump sum cash payment, while the coal sale price will be reduced and PacifiCorp's minimum annual coal purchase obligation will increase. Under the terms of a new coal sales agreement, Wyodak Resources will sell additional coal for delivery to other PacifiCorp power plants from late 2001 through 2003, and Wyodak Resources will also have an option to sell additional coal to PacifiCorp through 2010.

FOUNTAIN VALLEY ACQUISITION

In April 2001, we purchased from Enron Corporation 100% of an independent power project under construction near Colorado Springs, Colorado known as the "Fountain Valley" project. This site will initially house 240 megawatts of gas-fired peaking facilities. Upon completion of construction, 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. We plan to further develop this site, integrating our expanding gas-fired generation resources with our nearby fuel production and marketing activities and complementing our predominantly coal-fired generation facilities in Wyoming.

LONG-TERM POWER SALES CONTRACTS

In February 2001, we entered into long-term power sales agreements with Cheyenne Light, Fuel and Power Company and the Municipal Electric Agency of Nebraska to sell a total of 80 megawatts of capacity from the Wygen I facility, a mine-mouth coal-fired plant with a total capacity of 90 megawatts, which is expected to be completed by spring 2003. The agreements cover a period of 10 years from the date the plant becomes operational.

In March 2001, we entered into a unit contingent tolling agreement with Cheyenne Light, Fuel and Power Company for a 10-year term commencing in September 2001 for all of the energy and capacity from the Black Hills Generation Gillette CT facility, a 40 megawatt gas-fired combustine turbine facility which is scheduled to be completed in May 2001. We plan to operate this facility as a merchant plant during the summer of 2001.

LANGE PROJECT

In March 2001, we placed an order for a 40 megawatt gas-fired turbine that will be located either adjacent to the Wygen I and Black Hills Generation Gillette CT plants near Gillette, Wyoming, or adjacent to our transmission system in Rapid City, South Dakota. We expect to complete construction of the related power plant, known as the "Lange project," in the first quarter of 2002.

PURCHASE OF OIL AND GAS PROPERTIES

In April 2001, we purchased certain operating and non-operating interests in 74 oil and gas wells located primarily in Colorado and Wyoming for approximately $9 million from Stewart Petroleum Corporation. 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 of over 20% in our December 31, 2000 proved reserves. We expect to operate 35% of the wells representing approximately 85% of the reserves acquired.

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 formation of our holding company allows us to pursue, through separate subsidiaries, business opportunities in markets that are both regulated and unregulated. The shares offered by this prospectus are shares of common stock of the new holding company, Black Hills Corporation.

THE OFFERING

Common stock offered by us	3,000,000 shares
Common stock to be outstanding after the offering	25,951,394 shares(1)
Use of proceeds	Approximately $40 million to partially fund the construction of the following independent power projects: Arapahoe CC5, Valmont Unit 8, Black Hills Generation Gillette CT and the Lange project; and approximately $106.4 million to repay a portion of indebtedness owed under our revolving credit facilities. Remaining proceeds will be used for general corporate purposes, including funding of capital expenditures and potential acquisitions, the development and construction of new facilities and additions to working capital. See "Use of Proceeds."
New York Stock Exchange symbol	"BKH"

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(1) Based on the number of shares outstanding as of February 28, 2001. This number excludes:

- 450,000 shares that may be sold upon exercise of the underwriters' over-allotment option; and

- 1,048,254 shares reserved for issuance pursuant to outstanding stock options and upon conversion of our outstanding convertible preferred stock.

OUR EXECUTIVE OFFICES

We are incorporated in South Dakota and our headquarters and principal executive offices are located at 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57709. Our telephone number is (605) 721-1700.

SUMMARY CONSOLIDATED FINANCIAL DATA

The following table presents a summary of our pro forma and historical consolidated financial data derived from our pro forma and historical consolidated financial statements. The unaudited pro forma consolidated financial data give effect to the Indeck Capital and other related acquisitions pursuant to the purchase method of accounting for business combinations and were prepared based on the assumption that the purchases had been consummated as of January 1, 2000. You should read the unaudited pro forma consolidated financial data along with our pro forma and historical consolidated financial statements and related notes, and the section of this prospectus entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations." The unaudited pro forma consolidated financial data are not necessarily indicative of the results of operations that would have occurred had the transactions described above been consummated on the date assumed, nor are they necessarily indicative of future results of operations.

CONSOLIDATED INCOME STATEMENT DATA

	PRO FORMA	HISTORICAL				
	YEAR ENDED DECEMBER 31,	YEAR ENDED DECEMBER 31,				
	2000	2000	1999	1998	1997	1996
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)					
Revenues:						
Electric	$ 173,308	$ 173,308	$133,222	$129,236	$126,497	$118,718
Coal production	30,530	30,530	31,095	31,413	31,080	31,315
Fuel marketing	1,366,970	1,366,970	614,228	506,043	142,790	--
Oil and gas production	20,328	20,328	13,052	12,562	13,295	12,555
Independent power	84,675	39,660	--	--	--	--
Communications	11,371	11,371	3,423	--	--	--
Intersegment eliminations	(18,331)	(18,331)	(3,145)	--	--	--
Total revenues	1,668,851	1,623,836	791,875	679,254	313,662	162,588
Depreciation, depletion and amortization	35,012	32,864	25,067	24,037	22,311	22,794
Operating income	139,053	114,750	61,891	49,233	58,439	54,305
Other income and minority interest	(11,022)	(8,277)	2,614	(44)	45	1,744
Interest expense	40,292	30,342	15,460	14,707	14,123	13,942
Income tax expense	34,258	30,358	15,789	11,708	14,326	13,578
Net income available for common stock	57,542	52,770	37,067	25,808	32,359	30,252
Earnings per share--basic	$ 2.47	$ 2.39	$ 1.73	$ 1.60(1)	$ 1.49	$ 1.40
Earnings per share--diluted	$ 2.45	$ 2.37	$ 1.73	$ 1.60(1)	$ 1.49	$ 1.40
Weighted average shares of common stock outstanding:						
Basic	23,293	22,118	21,445	21,623	21,692	21,660
Diluted	23,543	22,281	21,482	21,665	21,706	21,660
Dividends paid per share of common stock	$ 1.08	$ 1.08	$ 1.04	$ 1.00	$ 0.95	$ 0.92

CONSOLIDATED BALANCE SHEET DATA

	AS OF DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
Current assets	$ 419,010	$186,357	$140,480	$ 84,009	$ 50,997
Net property, plant and equipment	794,281	453,745	389,607	401,127	400,434
Total assets	1,320,320	668,492	559,417	508,741	467,354
Current liabilities	588,856	210,510	102,582	53,807	28,115
Deferred credits and other liabilities	104,065	80,676	88,139	86,171	81,373
Long-term recourse debt(2)	158,687	160,700	162,030	163,360	164,691
Long-term non-recourse debt(2)	148,405	--	--	--	--
Stockholders' equity	282,346	216,606	206,666	205,403	193,175
Total liabilities and capitalization	1,320,320	668,492	559,417	508,741	467,354

CONSOLIDATED STATEMENT OF CASH FLOWS DATA

	YEAR ENDED DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
Cash flows from operating activities	$ 74,470	$ 73,743	$ 54,730	$ 56,049	$ 55,397
Cash flows used by investing activities	(167,029)	(136,057)	(35,931)	(30,830)	(29,093)
Cash flows from (used by) financing activities	100,990	64,032	(20,809)	(21,785)	(21,143)
Increase (decrease) in cash and cash equivalents	$ 8,431	$ 1,718	$ (2,010)	$ 3,434	$ 5,161

OTHER FINANCIAL DATA

	YEAR ENDED DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
EBITDA(3)	$139,337	$89,572	$86,726 (1)	$80,795	$78,843
Return on common stock equity	19.0%	17.1%	16.7%(1)	15.8%	15.7%

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(1) Excludes $13.5 million pre-tax, $8.8 million after tax, or $0.41 per share, non-cash write-down of oil and gas properties due to historically low crude oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

(2) Excluding current maturities of long-term debt.

(3) 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, as determined by generally accepted accounting principles, or as an indicator of operating performance or cash flows from operating, investing and financing activities, as determined by generally accepted accounting principles, and is thus susceptible to varying calculations. EBITDA as presented may not be comparable to other similarly titled measures of other companies.

RISK FACTORS

Before you invest in our common stock, you should be aware of the significant risks described below. You should carefully consider these risks, together with all of the other information included in this prospectus, before you decide whether to purchase shares of our common stock.

RISKS RELATING TO OUR INDUSTRY

OUR BUSINESS IS SUBJECT TO SUBSTANTIAL GOVERNMENTAL REGULATION AND PERMITTING REQUIREMENTS AND MAY BE ADVERSELY AFFECTED BY ANY FUTURE INABILITY TO COMPLY WITH EXISTING OR FUTURE REGULATIONS OR REQUIREMENTS.

IN GENERAL. Our business is subject to extensive energy, environmental and other laws and regulations of federal, state and local authorities. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to operate our facilities. We may incur significant additional costs because of our compliance with these requirements. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. In addition, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulation may have a detrimental effect on our business. Furthermore, with the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate, we expect our environmental expenditures to be substantial in the future.

ENERGY REGULATION. The Public Utility Holding Company Act of 1935, or PUHCA, and the Federal Power Act regulate public utility holding companies and their subsidiaries and place certain constraints on the conduct of their business. The Energy Policy Act of 1992 provides relief from regulation under PUHCA to exempt wholesale generators. Maintaining the status of our facilities as exempt wholesale generators is conditioned on their continuing to meet statutory criteria and could be jeopardized, for example, by the making of retail sales by an exempt wholesale generator in violation of the requirements of the Energy Policy Act.

We are continually in the process of obtaining or renewing federal, state and local approvals required to operate our facilities. Additional regulatory approvals may be required in the future due to a change in laws or regulations, or interpretations of existing laws and regulations, a change in our customers or other reasons. We may not always be able to obtain all required regulatory approvals, and we may not be able to obtain any necessary modifications to existing regulatory approvals or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain and comply with any required regulatory approvals, the operation of our facilities or the sale of electricity to third parties could be prevented or subject to additional costs.

ENVIRONMENTAL REGULATION. In July 1999, the United States Environmental Protection Agency 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 specified coal-fired generating units built between 1962 and 1977) by 2004 that would be subject to "best available retrofit technology," or BART. These sources will be required to implement BART within five years after the EPA approves 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. Currently, the best available technology consists of "scrubbers," which are devices that trap pollutants in power-plant stacks. While we have installed scrubbers in our Wyodak and Neil Simpson II plants, we have not done so at the remainder of our coal-fired plants. If the proposed guidance is adopted in its current form, management believes that the only existing plant where additional capital investment may be required in order to comply with Clean Air Act requirements is our Neil Simpson I plant. Any capital expenditures associated with bringing the plant into compliance are not expected to have a material adverse effect on our financial condition or results of operations.

In acquiring some of our facilities, we assumed on-site liabilities associated with the environmental condition of those facilities, regardless of when such liabilities arose and whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We strive at all times to be in compliance with all applicable environmental laws and regulations. However, steps to bring our facilities into compliance could be expensive, and thus could adversely affect our financial condition. Environmental and other governmental laws have also increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells and related facilities. Moreover, environmental laws and regulations can change. See "Business--Regulation."

WE FACE ONGOING CHANGES IN THE UNITED STATES UTILITY INDUSTRY THAT COULD AFFECT OUR COMPETITIVENESS.

The United States electric utility industry is currently experiencing increasing competitive pressures, primarily in wholesale markets, as a result of consumer demands, technological advances, deregulation, greater availability of natural gas-fired generation and other factors. The Federal Energy Regulatory Commission, or FERC, has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses and deregulation initiatives in a number of states may encourage further disaggregation. As a result, significant additional competitors could become active in the generation, transmission and distribution segments of our industry.

Proposals have been introduced in Congress to repeal PUHCA, and FERC has publicly indicated support for the PUHCA repeal effort. To the extent competitive pressures increase and the pricing and sale of electricity assumes more characteristics of a commodity business, the economics of domestic independent power generation projects may come under increasing pressure.

In addition, the independent system operators who oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. These types of price limitations and other mechanisms may adversely affect the profitability of our generation facilities that sell energy into the wholesale power markets. Given the extreme volatility and lack of meaningful long-term price history in some of these markets and the imposition of price limitations by independent system operators, we can offer no assurance that we will be able to operate profitably in all wholesale power markets.

WE HAVE SOME EXPOSURE TO MARKET DISRUPTIONS IN CALIFORNIA.

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. In April 2001, PG&E filed a voluntary petition for Chapter 11 bankruptcy protection.

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 California Independent System Operator, or 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% interest. The settlement agreement provides for the termination of a 30-year power purchase agreement, in exchange for which we are entitled to receive payments of approximately $4 million per year 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 April 2001, SCE, its parent, Edison International, and the California Department of Water Resources signed a "Memorandum of Understanding" under which the state would pay $2.76 billion to purchase SCE's high voltage transmission system and SCE would withdraw 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, the California Public Utilities Commission and FERC. 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.

RISKS RELATED TO OUR BUSINESS

COMPETITION IS INCREASING IN ALL OF OUR BUSINESSES.

In particular, the independent power industry is characterized by numerous strong and capable competitors, some of which have more extensive experience in the operation, acquisition and development of power generation facilities, larger staffs or greater financial resources than we do. Many of our competitors are also seeking favorable power generation opportunities. This competition may adversely affect our ability to make investments or acquisitions on attractive terms.

There also exists strong competition in all aspects of the oil and gas industry, including exploration, production and fuel marketing. We must compete with a substantial number of other energy companies, many of which have substantially greater financial, managerial, technical and other resources than we possess.

OUR BROADBAND COMMUNICATIONS BUSINESS IS SUBJECT TO SIGNIFICANT COMPETITION FOR ITS SERVICES AND TO RAPID TECHNOLOGICAL CHANGE.

Although our communications unit has achieved rapid penetration of our existing market, Black Hills FiberCom faces strong competition for its services from the incumbent local exchange carrier, which has dominated the local communications markets, as well as from long distance providers, Internet service providers, the incumbent cable television provider and others. The area's incumbent local exchange carrier has responded to our presence by offering an extended area service plan matching our market area. Internet service provider competition is currently limited primarily to dial-up services. Broadband services competing with our cable modem service are not widely available in our market, except for the small number of digital subscriber lines provided by the area's incumbent local exchange carrier. The incumbent cable television provider has upgraded its system, but not to the extent necessary to provide bundled services through its own facilities, and it must resell telephony services to compete with our bundled products. However, the incumbent cable television provider may respond with more competitive services as our market penetration increases.

The communications industry is subject to rapid and significant changes in technology. There can be no assurance that future technological developments will not have a material adverse effect on Black Hills FiberCom's competitive position. We do, however, expect that future technological developments will be based on fiber optic technology, and that we will be in an advantageous position to be the first in our market to deploy those technological advancements on a cost-effective basis.

Our ability to recover our capital investment and achieve operating profits is dependent on our ability to attract additional customers and is subject to the risk that technological advances may render our network obsolete. No assurance can be given that we will be successful in meeting our goals. If we determine that we will be unable to recover our investment, we would be required to take a non-cash charge to earnings in an amount that could be material in order to write down a portion of our investment in Black Hills FiberCom.

OUR RATE FREEZE AGREEMENT WITH THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION PREVENTS US FROM PASSING ON TO OUR SOUTH DAKOTA RETAIL UTILITY CUSTOMERS COST INCREASES THAT MAY BE INCURRED DURING THE RATE FREEZE PERIOD, ABSENT EXTRAORDINARY CIRCUMSTANCES.

Our utility's rate freeze agreement with the South Dakota Public Utilities Commission provides that, during the period ending January 1, 2005, Black Hills Power may not apply to the Commission for any increase in rates, except upon the occurrence of certain extraordinary events.

Although most of our utility's costs are fixed under long-term fuel and power supply agreements, our utility's historically stable returns could be threatened by plant outages, machinery failure, increases in purchased power costs over which our utility has no control, acts of nature or other unexpected events that could cause operating costs to increase. Since, however, we own or control generating capacity in excess of our historical peak demands, we do not anticipate that our utility will be required to purchase replacement power in wholesale power markets, except in the event of unexpected plant outages.

BECAUSE WHOLESALE POWER, FUEL PRICES AND OTHER COSTS ARE SUBJECT TO VOLATILITY, OUR REVENUES MAY FLUCTUATE.

A substantial portion of our growth in net income in recent years is attributable to increasing wholesale sales by our utility and our independent energy unit into a robust wholesale market. The prices of energy products in the wholesale power markets are influenced by many factors outside our control, including fuel prices, transmission constraints, supply and demand, weather, economic conditions, and the rules, regulations and actions of the system operators in those markets. Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

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

ESTIMATES OF OUR PROVED RESERVES MAY MATERIALLY CHANGE DUE TO NUMEROUS UNCERTAINTIES INHERENT IN ESTIMATING OIL AND NATURAL GAS RESERVES.

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

WE HAVE A LIMITED HISTORY OF SELLING AND MARKETING PRODUCTS IN THE WHOLESALE POWER MARKETS AND MAY NOT BE ABLE TO SUCCESSFULLY MANAGE THE RISKS ASSOCIATED WITH THIS ASPECT OF OUR BUSINESS.

We sell our energy, capacity and other energy products that are not otherwise committed under long-term contracts into wholesale power markets, either directly or through power marketers. We operate within strict limits, typically selling only our available capacity and not engaging in power marketing for others or in any speculative activity by selling in excess of what we reasonably believe our facilities are capable of producing or will produce. The overall objective of our power marketing activities is to optimize the utilization of our facilities to achieve an appropriate rate of return on our generation asset portfolio and our utility's off-system sales without taking any undue risks. Nevertheless, we have been managing risks associated with price volatility in this manner for only a limited amount of time. We and any power marketing company we hire may not be able to effectively manage this price volatility, and may not be able to successfully manage the other risks associated with trading in energy markets, including the risk that counterparties may not perform, especially if the current disruptions in the western markets worsen.

WE HAVE SUBSTANTIAL INDEBTEDNESS AND WILL REQUIRE SIGNIFICANT ADDITIONAL AMOUNTS OF DEBT AND EQUITY CAPITAL TO GROW OUR BUSINESSES. OUR FUTURE ACCESS TO SUCH FUNDS IS NOT CERTAIN.

As of December 31, 2000, we had short-term debt of $226 million, long-term recourse debt of $159 million and long-term non-recourse debt of $148 million. Our substantial debt presents the risk that we might not generate sufficient cash to maintain our credit facilities or service our indebtedness. In addition, our leveraged capital structure could limit our ability to finance the acquisition and development of additional projects, to compete effectively, to operate successfully under adverse economic conditions and to fully implement our strategy. The terms of our debt may also restrict our flexibility in operating our projects.

In order to access capital on a substantially non-recourse basis in the future, we may have to make larger equity investments in, or provide more financial support for, our project subsidiaries. We also may not be successful in structuring future financing for our projects on a substantially non-recourse basis.

The South Dakota Constitution requires shareholder approval of corporate indebtedness and prohibits South Dakota corporations, such as us, from incurring recourse debt in excess of levels previously approved by shareholders. At our next annual shareholders meeting in May 2001, we intend to ask our shareholders to approve an increase in the level of authorized borrowings from $500 million to $2 billion in order to support the future growth of our independent energy business. No assurance can be given, however, that our shareholders will approve this additional borrowing authority. Any failure to obtain additional borrowing authority could inhibit our ability to pursue our growth plan.

We estimate that our communications unit will require approximately $25 million of additional financing to substantially complete the construction of its network in 2001. To date, we have generated capital for our independent energy investments and our communications network principally through internally-generated cash flow and through borrowings. We cannot assure you that we will continue to generate sufficient cash flow or that we will be able to raise additional debt or equity capital from others in the future.

OUR POWER PROJECT DEVELOPMENT, EXPANSION AND ACQUISITION ACTIVITIES, OUR OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES AND THE CONSTRUCTION OF OUR COMMUNICATIONS NETWORK MAY NOT BE SUCCESSFUL, WHICH WOULD IMPAIR OUR ABILITY TO EXECUTE OUR GROWTH STRATEGY.

The growth of our independent power business through development, expansion and acquisition activities is critical to our future growth. While we are currently developing new facilities and expanding existing projects, with a significant development backlog, we may not be able to continue to develop attractive opportunities or to complete acquisitions or development projects that we undertake. Factors that could cause our activities to be unsuccessful include competition, our inability to obtain required governmental permits and approvals, and our inability to negotiate acceptable acquisition, construction, fuel supply or other material agreements.

Similarly, we expect to continue to evaluate and pursue oil and gas acquisition opportunities on terms which management considers favorable. Our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including accidents, title problems, weather conditions, shortages or delays in delivery of equipment or compliance with governmental requirements.

There are relatively few manufacturers of the hybrid fiber coaxial cable equipment we are using to build our broadband communications network. Although construction is approximately 75% complete, any difficulties we experience in identifying satisfactory suppliers or alternative sources of equipment could delay the completion of our network, impede our ability to connect new customers and cause our communications unit to experience operating losses for a longer period than currently expected.

CONSTRUCTION, EXPANSION, REFURBISHMENT AND OPERATION OF POWER GENERATION FACILITIES INVOLVE SIGNIFICANT RISKS THAT CANNOT ALWAYS BE COVERED BY INSURANCE OR CONTRACTUAL PROTECTIONS.

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

- inability to obtain required governmental permits and approvals;

- unavailability of equipment;

- supply interruptions;

- work stoppages;

- labor disputes;

- social unrest;

- weather interferences;

- unforeseen engineering, environmental and geological problems; and

- unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, especially in the case of newer environmental emission control technology. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damages payments. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses, higher maintenance costs and penalties. As a result, a project may operate at a loss or be unable to fund principal and interest payments under its project financing agreements, which may result in a default under that project's indebtedness.

RISKS RELATING TO OUR CORPORATE STRUCTURE

PROVISIONS OF SOUTH DAKOTA LAW AND OUR ARTICLES OF INCORPORATION AND BYLAWS, AND SEVERAL OTHER FACTORS, COULD LIMIT ANOTHER PARTY'S ABILITY TO ACQUIRE US AND COULD DEPRIVE YOU OF THE OPPORTUNITY TO OBTAIN A TAKEOVER PREMIUM FOR YOUR SHARES OF COMMON STOCK.

A number of provisions under South Dakota law and that are contained in our articles of incorporation and bylaws could make it more difficult for another company to acquire us and for you to receive any related takeover premium for your shares. These provisions, among other things:

- provide for a classified board of directors, which allows only one-third of our directors to be elected each year;

- restrict the ability of shareholders to take action by written consent and to call a special meeting;

- authorize the board of directors to designate the terms of and issue new series of preferred stock; and

- impose restrictions on business combinations with certain interested parties.

In addition, the South Dakota Public Utility Commission may assert jurisdiction to review and authorize certain business combinations or other acquisitions of our capital stock. Any attempt to obtain control of us by means of a tender offer, merger or otherwise could be discouraged, delayed or prevented if the South Dakota Public Utility Commission determined that it has the authority or the obligation to review the transaction.

LIQUIDITY RISKS

WE CANNOT ASSURE YOU THAT A HIGHLY ACTIVE TRADING MARKET FOR OUR COMMON STOCK WILL DEVELOP.

We have not offered common stock in the public market since 1993 and our common stock currently lacks the level of liquidity or high trading volume enjoyed by some of our competitors. The continued absence of a highly active trading market for our common stock could cause our stock price to fluctuate significantly.

USE OF PROCEEDS

We expect that the net proceeds from this offering of common stock will be approximately $146.4 million, after deducting discounts to the underwriters and estimated expenses of this offering that we will pay. Approximately $40 million of the net proceeds will be used to partially fund the Arapahoe CC5 and Valmont Unit 8 plant expansions and the construction of the Black Hills Generation Gillette CT and Lange projects. An additional $106.4 million will be used to repay a portion of current indebtedness under our revolving credit facilities with ABN AMRO Bank N.V., as agent. Borrowings under our $115 million revolving credit facility bear interest at a floating rate, which at March 31, 2001, was 6.46%. Borrowings under our $50 million credit facility also bear interest at a floating rate, which at March 31, 2001, was 5.71%. During the last year, we have used borrowings under these credit facilities to expand our independent energy business, including approximately $36 million to fund our equity contribution in the Fountain Valley project and approximately $9 million to fund the purchase of 74 oil and gas wells from Stewart Petroleum Corporation in April 2001.

Any remaining net proceeds will be used for general corporate purposes, which may include funding of capital expenditures and potential acquisitions, the development and construction of new facilities and additions to working capital.

PRICE RANGE OF COMMON STOCK AND DIVIDENDS

Our common stock trades on the New York Stock Exchange under the symbol "BKH." The following table sets forth the high and low sale prices per share of our common stock, as reported in the New York Stock Exchange composite transactions, and the cash dividends paid per share of common stock, for the periods indicated:

	HIGH	LOW	DIVIDENDS PAID
1999			
First Quarter	$26.50	$21.00	$0.26
Second Quarter	23.88	21.00	0.26
Third Quarter	25.63	22.19	0.26
Fourth Quarter	23.31	20.31	0.26
2000			
First Quarter	25.19	20.44	0.27
Second Quarter	25.19	20.88	0.27
Third Quarter	30.13	22.00	0.27
Fourth Quarter	46.06	27.00	0.27
2001			
First Quarter	45.74	31.00	0.28
Second Quarter (through April 18)	55.25	45.81	--

As of January 31, 2001, the common stock was held by 5,708 holders of record and approximately 11,800 beneficial owners.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects. Our credit facilities contain restrictions on the payment of cash dividends, the most restrictive of which prohibit the payment of cash dividends if our interest coverage ratio, as calculated in our credit agreements, is less than 2.0:1.0.

CAPITALIZATION

The table below shows our cash position and capitalization as of December 31, 2000 on an actual basis and on an adjusted basis to give effect to estimated net proceeds from this offering and the application of the net proceeds, including the repayment of a portion of our indebtedness under two of our credit facilities, as described under "Use of Proceeds."

You should read this table in conjunction with our consolidated financial statements and related notes that are included in this prospectus.

	DECEMBER 31, 2000 ACTUAL	DECEMBER 31, 2000 AS ADJUSTED
	(IN THOUSANDS)	
Cash and cash equivalents	$ 24,913	$ 24,913
Current portion of long-term debt	13,960	13,960
Short-term debt	211,679	105,279
Total short-term debt	225,639	119,239
Long-term debt	307,092	307,092
Shareholders' equity:		
Preferred stock	4,000	4,000
Common stock	23,302	26,302
Additional paid-in capital	73,442	216,842
Retained earnings	191,482	191,482
Treasury stock	(9,067)	(9,067)
Accumulated other comprehensive income	(813)	(813)
Total shareholders' equity	282,346	428,746
Total capitalization	$589,438	735,838

SELECTED CONSOLIDATED FINANCIAL DATA

The following table presents a summary of our pro forma and historical consolidated financial data derived from our pro forma and historical consolidated financial statements. The unaudited pro forma consolidated financial data give effect to the Indeck Capital and other related acquisitions pursuant to the purchase method of accounting for business combinations and were prepared based on the assumption that the purchases had been consummated as of January 1, 2000. You should read the unaudited pro forma consolidated financial data along with our pro forma and historical consolidated financial statements and related notes, and the section of this prospectus entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations." The unaudited pro forma consolidated financial data are not necessarily indicative of the results of operations that would have occurred had the transactions described above been consummated on the date assumed, nor are they necessarily indicative of future results of operations.

CONSOLIDATED INCOME STATEMENT DATA

	PRO FORMA	HISTORICAL				
	YEAR ENDED DECEMBER 31,	YEAR ENDED DECEMBER 31,				
	2000	2000	1999	1998	1997	1996
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)					
Revenues:						
Electric	$ 173,308	$ 173,308	$133,222	$129,236	$126,497	$118,718
Coal production	30,530	30,530	31,095	31,413	31,080	31,315
Fuel marketing	1,366,970	1,366,970	614,228	506,043	142,790	--
Oil and gas production	20,328	20,328	13,052	12,562	13,295	12,555
Independent power	84,675	39,660	--	--	--	--
Communications	11,371	11,371	3,423	--	--	--
Intersegment eliminations	(18,331)	(18,331)	(3,145)	--	--	--
Total revenues	1,668,851	1,623,836	791,875	679,254	313,662	162,588
Depreciation, depletion and amortization	35,012	32,864	25,067	24,037	22,311	22,794
Operating income	139,053	114,750	61,891	49,233	58,439	54,305
Other income and minority interest	(11,022)	(8,277)	2,614	(44)	45	1,744
Interest expense	40,292	30,342	15,460	14,707	14,123	13,942
Income tax expense	34,258	30,358	15,789	11,708	14,326	13,578
Net income available for common stock	57,542	52,770	37,067	25,808	32,359	30,252
Earnings per share--basic	$ 2.47	$ 2.39	$ 1.73	$ 1.60(1)	$ 1.49	$ 1.40
Earnings per share--diluted	$ 2.45	$ 2.37	$ 1.73	$ 1.60(1)	$ 1.49	$ 1.40
Weighted average shares of common stock outstanding:						
Basic	23,293	22,118	21,445	21,623	21,692	21,660
Diluted	23,543	22,281	21,482	21,665	21,706	21,660
Dividends paid per share of common stock	$ 1.08	$ 1.08	$ 1.04	$ 1.00	$ 0.95	$ 0.92

CONSOLIDATED BALANCE SHEET DATA

	AS OF DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
Current assets	$ 419,010	$186,357	$140,480	$ 84,009	$ 50,997
Net property, plant and equipment	794,281	453,745	389,607	401,127	400,434
Total assets	1,320,320	668,492	559,417	508,741	467,354
Current liabilities	588,856	210,510	102,582	53,807	28,115
Deferred credits and other liabilities	104,065	80,676	88,139	86,171	81,373
Long-term recourse debt(2)	158,687	160,700	162,030	163,360	164,691
Long-term non-recourse debt(2)	148,405	--	--	--	--
Stockholders' equity	282,346	216,606	206,666	205,403	193,175
Total liabilities and capitalization	1,320,320	668,492	559,417	508,741	467,354

CONSOLIDATED STATEMENT OF CASH FLOWS DATA

	YEAR ENDED DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
Cash flows from operating activities	$ 74,470	$ 73,743	$ 54,730	$ 56,049	$ 55,397
Cash flows used by investing activities	(167,029)	(136,057)	(35,931)	(30,830)	(29,093)
Cash flows from (used by) financing activities	100,990	64,032	(20,809)	(21,785)	(21,143)
Increase (decrease) in cash and cash equivalents	$ 8,431	$ 1,718	$ (2,010)	$ 3,434	$ 5,161

OTHER FINANCIAL DATA

	YEAR ENDED DECEMBER 31,				
	2000	1999	1998	1997	1996
	(IN THOUSANDS)				
EBITDA(3)	$139,337	$89,572	$86,726 (1)	$80,795	$78,843
Return on common stock equity	19.0%	17.1%	16.7%(1)	15.8%	15.7%

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(1) Excludes $13.5 million pre-tax, $8.8 million after tax, or $0.41 per share, non-cash write-down of oil and gas properties due to historically low crude oil prices, lower natural gas prices and a decline in the value of unevaluated properties.

(2) Excluding current maturities of long-term debt.

(3) 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, as determined by generally accepted accounting principles, or as an indicator of operating performance or cash flows from operating, investing and financing activities, as determined by generally accepted accounting principles, and is thus susceptible to varying calculations. EBITDA as presented may not be comparable to other similarly titled measures of other companies.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion in conjunction with "Risk Factors," "Selected Consolidated Financial Data" and our consolidated financial statements and the related notes included elsewhere in this prospectus.

OVERVIEW

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 communication 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%, 17.1% and 12.5% 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%. 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% increase in 2000 and a 17% 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 and $2.15 per million British thermal units in 1998 and 1999, respectively, to $4.19 per million British thermal units in 2000. Daily volumes of natural gas marketed increased 35%, 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%

	2000	1999	1998
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, as determined by generally accepted accounting principles, or as an indicator of operating performance or cash flows from operating, investing and financing activities, as determined by generally accepted accounting principles, and is thus susceptible to varying calculations. 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*

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* Since the date of acquisition.

The independent energy business group's revenues increased 119% in 2000 and 20% 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% in 2000 and 21% 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%, 160% and 329%, respectively, in 2000 compared to 1999. Net income of this group increased 144% 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

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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.

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 business. 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% in 2000 compared to 3.1% in 1999 compared to 1998. The increase in electric revenue in 2000 was primarily due to a 54% 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. Megawatt hours 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 kilowatt hour sales increased 2.8% in 2000 compared to 1999 and declined 0.1% in 1999 compared to 1998. Residential and commercial sales increases of 6% and 3%, respectively, in 2000 were partially offset by a 2% decrease in industrial sales, primarily due to load reductions at Homestake Gold Mine. Degree days, a measure of weather trends, were 16% above 1999 and 1% above normal in 2000. Degree days in 1999 were 9% below 1998 and 13% below normal. The increase in electric revenue in 1999 was primarily due to stable firm sales combined with a 20% increase in off-system sales.

Revenue per kilowatt hour 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 56,856 in 1998.

The revenue per kilowatt hour sold in 2000 reflects a 54% increase in wholesale non-firm sales to 684,378 megawatt hours and robust wholesale power prices. The revenue per kilowatt hour sold in 1999 reflects the 20% increase in wholesale non-firm sales to 445,712 megawatt hours. The revenue per kilowatt hour sold in 1998 reflects the 33% increase in wholesale non-firm sales to 371,104 megawatt hours.

Electric utility operating expenses increased by 30% 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% 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%, with the system demand forecasted to increase at a rate of 2%. 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 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 capital deployment. As of December 31, 2000, we had 8,368 residential customers and 646 business customers.

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, including short- and long-term debt and preferred and common stock, 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 dividend growth rate was 4.4% and our payout ratio for 2000 was 45%. In January 2001, our board of directors increased the quarterly dividend 3.7% 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 the 240 megawatt Fountain Valley gas-fired turbine generation facility located near Colorado Springs, Colorado, which was completed in April 2001. Construction is expected to be completed in 2001, with an expected total acquisition and construction 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% financial interest in this project.

- Acquisition of operating and non-operating interests in 74 gas and oil wells from Stewart Petroleum Corporation, which was 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 spring 2003.

Forecasted capital expenditures for our electric utility operations include new transmission and substation projects, rebuild 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 have 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 $75 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.

Some of the lines of credit discussed above are secured by some of our assets.

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% and 43%, respectively. With expected growth within the independent energy business group, we anticipate our long-term debt ratio will increase to 55-60% 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 (MMBTUS)	MAXIMUM TERM (YEARS)
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

	VOLUME COVERED (TONS)	MAXIMUM TERM (YEARS)
Coal tons sold	988,000	1
Coal tons purchased	896,000	1

DECEMBER 31, 1999	VOLUME COVERED (MMBTUS)	MAXIMUM TERM (YEARS)
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 adverse 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%) 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% 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 earnings realized from more efficient operations, sales from load growth, and off-system sales of power and energy until a subsequent general rate proceeding is initiated to modify our rates.

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% 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 noncash 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.

RECENT DEVELOPMENTS AND ACQUISITIONS

Although our results of operations for the first quarter of 2001 are not currently available, the following information reflects our expectations with respect to these results based on currently available information. We expect our earnings for the first quarter of 2001 to reach record levels of approximately $1.30 to $1.35 per share, compared to $0.42 per share reported for the same quarter of 2000. The anticipated higher earnings in the first quarter of 2001 are primarily due to the continued strong performance of our wholesale gas marketing business and increased wholesale electric sales. We also expect earnings for our independent energy business group to exceed our electric utility's earnings for the first quarter of 2001. A portion of the increased earnings is attributable to continued unusual conditions in western gas and electricity markets. We also expect that our communications business group will report continued losses in the first quarter due to capital costs and related financing costs. We expect to report our first quarter financial results on or about May 4, 2001.

In April 2001, we purchased from Enron Corporation 100% of an independent power project under construction near Colorado Springs, Colorado known as the "Fountain Valley" project. This site will initially house 240 megawatts of gas-fired peaking facilities. Upon completion of construction, 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. We plan to further develop this site, integrating our expanding gas-fired generation resources with our nearby fuel production and marketing activities and complementing our predominantly coal-fired generation facilities in Wyoming.

In April 2001, we purchased certain operating and non-operating interests in 74 oil and gas wells located primarily in Colorado and Wyoming for approximately $9 million from Stewart Petroleum Corporation. 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 of over 20% in our December 31, 2000 proved reserves. We expect to operate 35% of the wells representing approximately 85% of the reserves acquired.

BUSINESS

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	5-YR. CAGR(1)
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	16%
Earnings per Share	$ 2.37	$ 1.73	$ 1.60(2)	$ 1.49	$ 1.40	15%
Assets ($ in millions)	$ 1,320	$ 668	$ 559	$ 509	$ 467	24%
Capital Expenditures ($ in millions)	$ 177.2	$ 154.6	$ 27.2	$ 28.3	$ 24.4	28%
Electric Sales (megawatt hours):						
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	11%
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)	--	
Energy Marketing Gross Margins ($ in thousands)	$ 41,783	$ 9,275	$ 7,824	$ 1,736	$ 0	
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	
Exploration and Production Reserves:						
Total MMcfe Reserves	44,882	44,114	30,160	24,022	17,330	

(1) Compound annual growth rate.

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

(3) Since date of inception of marketing operations.

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 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. The shares offered by this prospectus are shares of common stock of the new holding company, Black Hills Corporation.

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, 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 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:

- 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;

- 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;

- 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;

- 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

- 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 ADVANTAGES AND OUR OPERATING AND MARKETING EXPERTISE TO REMAIN A LOW-COST POWER PRODUCER. We expect to expand our portfolio of power plants having relatively low marginal costs of producing energy and related products and services. 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 and signed tolling agreements for these expanded facilities as well as the Fountain Valley project.

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 April 2001, we purchased from Enron Corporation 100% of an independent power project under construction near Colorado Springs, Colorado and known as the "Fountain Valley" project. 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 complete 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% of net unregulated capacity being gas-fired, 13% 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% coal-fired, 33% oil or gas-fired, and 14% 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% to 80% 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%. 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% 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% 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% and 60% 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% 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 the 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 May 2001 and by 50 megawatts at the Arapahoe plant by May 2002. In August 2000, we closed on a $60 million non-recourse project financing for the first phase of this expansion. We plan to finance our remaining construction costs through internally generated funds and additional non-recourse financing expected to close in the second quarter of 2001.

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. We anticipate that approximately $36 million of the net proceeds of this offering will be used to repay indebtedness incurred to pay a portion of the $175 million purchase price and related construction costs. 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-mouth 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 Neil Simpson II facility, completed in 1995. The two plants will 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 requirements are reduced or eliminated 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 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. For a discussion of some issues relating to the operation of the Harbor and Ontario plants, see "Risk Factors--Risks Relating to Our Industry--We have some exposure to market disruptions in California."

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 expansion 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% of the Hudson Falls and the South Glens Falls plants as part of the Indeck Capital acquisition and an additional 20% 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. 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	NUMBER OF PLANTS	TOTAL CAPACITY (MWS)	OUR EQUITY INTEREST	NET CAPACITY (MWS)
Energy Investors Fund I	7	136.0	12.6%	17.1
Energy Investors Fund II	6	130.0	6.9%	9.0
Project Finance Fund III	7	239.0	5.3%	12.7
Caribbean Basin	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.

In August 2000, Black Hills Energy Capital obtained $60 million in non-recourse project financing in conjunction with the Arapahoe (80 megawatt) and Valmont (40 megawatt) projects which were brought into service in 2000. We anticipate using approximately $36 million of the net proceeds of this offering to repay indebtedness incurred to fund our equity contribution in the Fountain Valley project. The remainder of the purchase price was funded, and the related construction costs are expected to be funded, with non-recourse project financing.

In addition to project financing, we have obtained a credit facility to provide flexibility in financing the growth of the independent energy group. In July 2000, in conjunction with the closing of the Indeck Capital acquisition, Black Hills Energy Capital obtained a new $115 million revolving credit facility.

FUEL PRODUCTION

COAL

Our coal production unit 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% and 9.0%, 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 unit'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% interest in the Wyodak plant is determined under a coal supply agreement terminating in 2022. For a description of litigation with PacifiCorp relating to a predecessor coal supply agreement and the settlement agreement resolving this litigation and establishing a new coal supply agreement, see "--Legal Proceedings."

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:

- PacifiCorp, under the terms of the new coal supply agreement and other coal sales agreements entered into in connection with the settlement of the PacifiCorp litigation;

- 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 unit operates 324 oil and gas wells located in Wyoming and Colorado. 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 389 wells located in California, Montana, North Dakota, Texas, Wyoming, Colorado, 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% of current production consisting of natural gas. In 2000, our oil and gas production increased 12% over 1999 levels, with record drilling results and year-end reserves.

In April 2001, we purchased certain operating and non-operating interests in 74 oil and gas wells located primarily in Colorado and Wyoming. 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%.

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.

Our gas marketing unit maintains a $75 million credit facility with Bank of America, N.A., as agent. We provide no guarantees or other forms of support for this facility.

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% 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.

Our oil marketing unit maintains a $25 million transactional-based credit facility (with a $12.5 million overdraft line) with Bank of America, N.A., as agent. The line of credit provides credit support for the purchase of crude oil. We provide no guarantees or other forms of support for this facility.

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.

Our coal marketing unit maintains a $4 million credit facility with Fifth Third Bank, N.A., as agent. Our coal mining subsidiary, Wyodak Resources Development Corporation, provides a $1 million guarantee on this facility.

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.

EDGAR REPRESENTATION OF DATA POINTS USED IN PRINTED GRAPHIC

CUSTOMER MIX
BASED ON 2000 REVENUE

RESIDENTIAL	20%
Municipal	1%
Commercial	26%
Off-system Wholesale	29%
Industrial	14%
Contract Wholesale	10%

EDGAR REPRESENTATION OF DATA POINTS USED IN PRINTED GRAPHIC

FUEL MIX

DIESEL	3%
Coal	62%
Gas	10%
Oil/Gas	25%

DISTRIBUTION AND TRANSMISSION. Our electric utility distribution and transmission businesses serve approximately 58,600 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% 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% wholesale off-system sales, 26% commercial, 20% residential, 14% industrial, 10% contract wholesale and 1% municipal. Approximately 68% 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% in 1999 and 5% 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% 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 CT's 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% (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% residential market penetration within our service territory while serving 35% of all broadband business customers in that territory.

The construction of our communications network is approximately 75% 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. We expect our communications unit to sustain approximately $10 million in net losses in 2001, with annual losses decreasing and profitability expected in the next three to four years.

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 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.

FINANCING

In the past, we have relied upon internally generated funds and short- and long-term debt to finance our activities. We expect that an appropriate mix of financing options, including short- and long-term debt and preferred and common stock, will be used to finance future activities. With expected growth in the independent energy business unit, we anticipate that our long-term debt ratio will increase to 55% to 60% over the next five years. We expect to finance the growth of our independent power unit primarily with project financing. See "--Independent Power Plants--Financing of our Independent Power Projects."

We currently have bank lines of credit totaling $290 million which provide for interim borrowings and the opportunity for timing of permanent financing. As of December 31, 2000, we had $211 million in notes and $20.6 million in letters of credit outstanding under these lines. There are no compensating balance requirements associated with these lines of credit.

In addition to the above lines of credit, Enserco Energy, Inc., our gas marketing unit, has a $90 million uncommitted, discretionary credit facility. This borrowing base line of credit provides credit support for the purchase of natural gas. We and our subsidiaries provide no guarantee to the lender. At December 31, 2000, Enserco had letters of credit outstanding of $69.8 million.

Black Hills Energy Resources, Inc., our oil marketing and transportation unit, has a $25 million, uncommitted, discretionary credit facility. This transaction line of credit provides credit support for the purchases of crude oil. We and our subsidiaries provide no guarantee to the lender. At December 31, 2000, Black Hills Energy Resources had letters of credit outstanding of $8.5 million.

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.

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 sulphur dioxide "allowances" for each ton of sulphur 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 sulphur dioxide emissions through the use of low sulphur 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 allowance 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 any penalties has been issued.

In July 1999, the United States Environmental Protection Agency 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 some 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. See "Risk Factors--Risks Relating to our Industry." 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 these 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% 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% 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 will not be imposed that would cause an unexpected material increase in reclamation costs.

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

BEN FRENCH OIL SPILL. In 1990 and 1991, we discovered extensive underground fuel oil contamination at the Ben French plant site. With the help of expert consultants, we worked closely with the South Dakota Department of Environment and Natural Resources to assess and remediate the site. Our assessment and remediation efforts continue today and we continue to monitor the site. All of our underground oil-carrying facilities from which the contamination occurred are now above ground. There have been no significant recoveries of free fuel oil product since 1994. Soil borings and monitoring wells on the perimeters of our Ben French plant property provide no indication of contamination beyond the property's limits. Management believes that the underground spill has been sufficiently remedied so as to prevent any oil from migrating off site. However, due to underground gypsum deposits in this area, the fuel oil has the potential of migrating to area waterways. In such event, cleanup costs could be greatly increased. Management believes that sufficient remediation efforts to prevent such a migration are currently in place, but due to the uncertainties of underground geology, no assurance can be given.

Cleanup costs recognized to date total approximately $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 Environmental Protection Agency 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 discussed in this prospectus, 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.

LEGAL PROCEEDINGS

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 for the Wyodak plant. We believe that PacifiCorp failed to make complete payment to us for coal sold under the coal supply agreement and that PacifiCorp was underpaying its coal bill by approximately $100,000 per month. We asked for relief in the amount of $5 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 to $40 million over an undefined period.

In April 2001, we entered into a settlement agreement with PacifiCorp whereby ongoing litigation between the parties has been withdrawn. A new coal supply contract and other agreements were executed as a result of the settlement. The new coal supply contract for the Wyodak plant extends the term of the prior contract from 2013 to 2022. Our subsidiary, Wyodak Resources, will receive a lump sum cash payment, while the coal sales price will be reduced and PacifiCorp's minimum annual coal purchase obligation will increase. Under the terms of a new coal sales agreement, Wyodak Resources will sell additional coal for delivery to other PacifiCorp power plants from late 2001 through 2003, and Wyodak Resources will also have an option to sell additional coal to PacifiCorp through 2010.

There are no 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. Except as otherwise described in this prospectus, 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.

MANAGEMENT

The name, age and title of each of our directors and executive officers and some of our key employees are as follows:

NAME	AGE	TITLE
Daniel P. Landguth	54	Director, Chairman of the Board and Chief Executive Officer
Adil M. Ameer	48	Director
Bruce B. Brundage	65	Director
David C. Ebertz	55	Director
Gerald R. Forsythe	60	Director
John R. Howard	60	Director
Everett E. Hoyt	61	Director, President and Chief Operating Officer
Kay S. Jorgensen	49	Director
David S. Maney	37	Director
Thomas J. Zeller	53	Director
Gary R. Fish	42	President and Chief Operating Officer of Independent Energy
Mark T. Thies	37	Senior Vice President and Chief Financial Officer
Thomas M. Ohlmacher	49	Senior Vice President--Power Supply and Power Marketing
James M. Mattern	46	Senior Vice President--Corporate Administration
Ronald D. Schaible	56	Senior Vice President and General Manager--Communications
Roxann R. Basham	39	Vice President--Controller
David R. Emery	38	Vice President--Fuel Resources
Kyle D. White	41	Vice President--Corporate Affairs
Steven J. Helmers	44	General Counsel and Corporate Secretary
Shawn T. McLaughlin	31	President of Enserco Energy, Inc.
John W. Salyer, Jr	42	President and Chief Operating Officer of Black Hills Energy Capital, Inc.

DANIEL P. LANDGUTH was elected our Chairman of the Board and Chief Executive Officer in January 1991. He has been a director since 1989 and currently chairs the Executive Committee. He has 30 years of experience with Black Hills. Mr. Landguth holds a B.S. degree in Electrical Engineering from the South Dakota School of Mines and Technology.

ADIL M. AMEER has been President and Chief Executive Officer of Rapid City Regional Hospital since 1991. From 1982 to 1991, he held several executive positions at the hospital. The hospital system owns and manages several health care facilities in Rapid City and the Black Hills area, and in Nebraska and Wyoming. Mr. Ameer was elected to the board of directors in 1997 and currently chairs the Audit Committee.

BRUCE B. BRUNDAGE has been President and Director of Brundage & Company, Englewood, Colorado, since 1973. Brundage & Company specializes in negotiation, appraisal and arrangement of mergers and acquisitions for a nationwide client base and in providing financial, advisory and private placement financing to businesses in the western United States. Mr. Brundage has been a director since 1986. He also serves as a director of Vicorp Restaurants, Inc.

DAVID C. EBERTZ has been a consultant with Dave Ebertz Risk Management Consulting, a firm specializing in insurance and risk management services for schools and public entities, since January 2000. From 1976 until December 1999, he was President and majority owner of Barlow Agency, Inc., Gillette, Wyoming, which provides risk management and insurance services primarily to the manufacturing, oil and gas, and mining industries. Mr. Ebertz has served on the board of directors since 1998 and currently chairs the Compensation Committee.

GERALD R. FORSYTHE is Chairman and Chief Executive Officer of Indeck Power Equipment Company, the largest emergency and back-up steam generating source in North America. Mr. Forsythe has been employed in various positions with Indeck Power Equipment Company since 1963. He is also Chairman and Chief Executive Officer of Indeck Energy Services, Inc. Mr. Forsythe joined our board of directors in July 2000. He also serves as a director of Championship Auto Racing Team, Inc.

JOHN R. HOWARD has been President of Industrial Products, Inc. since 1992. Industrial Products, Inc. provides equipment and supplies to the mining and manufacturing industries. He is also Special Projects Manager for Linweld, Inc. Mr. Howard joined the board of directors in 1977.

EVERETT E. HOYT has been our President and Chief Operating Officer since February 2001. From 1989 to February 2001, he was President and Chief Operating Officer of our regulated utility business. Mr. Hoyt was elected to the board of directors in 1991. Prior to joining us, Mr. Hoyt was employed by NorthWestern Corporation for 16 years where he served as Senior Vice President-Legal and as a member of the board of directors. He holds a B.S. degree in Mechanical Engineering from the South Dakota School of Mines and Technology and a J.D. from the University of South Dakota School of Law.

KAY S. JORGENSEN is a co-owner and Vice President of Jorgensen-Thompson Creative Broadcast Services, providing radio broadcast services in the western United States. Previously, she served in the South Dakota State Legislature for several terms and has served on various state and local boards and commissions. Ms. Jorgensen joined the board of directors in 1992.

DAVID S. MANEY has been a telecommunications venture capital investor and consultant since November 2000. Prior to that, he founded Worldbridge Broadband Services, Inc., a nationwide provider of outsourced field operations and technical services to the telecommunications industry, in 1994, and served as its President and Chief Executive Officer. In 1999, he co-founded, as a spin-off from Worldbridge, Open Access Broadband Networks, Inc., whose mission was to build and operate broadband carriers' carrier telecommunications networks in the residential local loop. He served as President and Chief Executive Officer of Open Access Broadband until November 2000. Previously, he held management positions with InterMedia Partners and Chronicle Publishing Company. Mr. Maney has been a member of the board of directors since 1999.

THOMAS J. ZELLER has been President of RE/SPEC Inc. since 1995. RE/SPEC is a technical consulting and services firm with expertise in engineering, environmental and information technologies. Mr. Zeller is also Chairman of the Board of Teachmaster Technologies, Inc., an educational software and consulting firm. Mr. Zeller has been a member of the board of directors since 1997 and currently chairs the Nominating Committee.

GARY R. FISH has been the President and Chief Operating Officer of our Independent Energy Group since September 1999. Prior to that, he served in several development and accounting officer positions for us since August 1988. Mr. Fish holds a B.S. in Business Administration from the University of South Dakota and is a certified public accountant.

MARK T. THIES has been our Senior Vice President and Chief Financial Officer since March 2000. From May 1997 to March 2000, he was our Controller. From 1990 to 1997, Mr. Thies served in a number of accounting positions with InterCoast Energy Company, an unregulated energy company and a wholly-owned subsidiary of MidAmerican Energy Holdings Company. Mr. Thies holds B.A.s in

Accounting and Business Administration from Saint Ambrose College and is a certified public accountant.

THOMAS M. OHLMACHER has been our Senior Vice President-Power Supply and Power Marketing since January 2001 and Vice President-Power Supply of Black Hills Power, Inc. since August 1994. Prior to that, he held several positions with us since 1974. Mr. Ohlmacher holds a B.S. in Chemistry from the South Dakota School of Mines and Technology.

JAMES M. MATTERN has been our Senior Vice President-Corporate Administration since September 1999, and was Vice President-Corporate Administration from January 1994 to September 1999. From 1997 to 1999, he was also Assistant to the CEO. Mr. Mattern has 12 years of experience with us. He holds a B.S. in Social Sciences and an M.S. in Administration from Northern State University.

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

ROXANN R. BASHAM has been our Vice President-Controller since March 2000. From December 1997 to March 2000, she was Vice President-Finance and Secretary/Treasurer. From 1993 until December 1997, she served as our Secretary/Treasurer, and has a total of 16 years of experience with us. She holds a B.S. in Business Administration from the University of South Dakota and is a certified public accountant.

DAVID R. EMERY has been our Vice President-Fuel Resources since January 1997. From June 1993 to January 1997, he was General Manager of Black Hills Exploration and Production. Mr. Emery has 12 years of experience with us. He holds a B.S. in Petroleum Engineering from the University of Wyoming and an M.S. in Business Administration from the University of South Dakota.

KYLE D. WHITE has been our Vice President-Corporate Affairs since January 2001 and Vice President-Marketing and Regulatory Affairs of Black Hills Power, Inc. since July 1998. Mr. White served as Director-Strategic Marketing and Sales from 1993 to January 1998 and Vice President-Energy Services from January 1998 to July 1998. He has a total of 18 years of experience with us. Mr. White holds a B.S. and M.S. in Business Administration from the University of South Dakota.

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

SHAWN T. MCLAUGHLIN has been an officer of Enserco Energy, Inc., our natural gas marketing subsidiary, since its inception in August 1996 and has been President since November 1998. Prior to that, Mr. McLaughlin was a trading analyst at KN Energy, Inc. from 1995 until August 1996. From 1991 to 1995, he was a floor trader at the Chicago Board of Trade. Mr. McLaughlin holds a B.A. in Economics from Colorado State University.

JOHN W. SALYER, JR. has been President and Chief Operating Officer of Black Hills Energy Capital, Inc. since its formation in mid-2000. Prior to that, he was co-founder and served as a Director, President and Chief Operating Officer of Indeck Capital, Inc. since its formation in 1994. Mr. Salyer also served as a Director and Senior Vice President of Finance from 1987 to 1994 for the affiliated company Indeck Energy Services, Inc. He holds a B.S. in Economics and Management from Elmhurst College.

ELECTION OF OFFICERS AND DIRECTORS

Our executive officers are elected by the board of directors and serve at its discretion. The members of our board of directors are elected to three classes of staggered three-year terms. Under a shareholders agreement among some of our shareholders and us, these shareholders currently have the right to nominate one director to our board. Gerald R. Forsythe is the current designee of these shareholders. For more information regarding the shareholders agreement, see "Principal Shareholders--Shareholders Agreement."

BOARD COMMITTEES

Our executive committee is comprised of Adil M. Ameer, Gerald R. Forsythe, John R. Howard, Everett E. Hoyt, Daniel P. Landguth, David S. Maney and Thomas J. Zeller, with Mr. Landguth serving as chairperson. The executive committee exercises the authority of the board of directors in the interval between meetings of the board, and recommends to the board of directors persons to be elected as officers or to be appointed to board committees.

Our compensation committee is comprised of Bruce B. Brundage, David C. Ebertz, Gerald R. Forsythe, John R. Howard, Kay S. Jorgensen and David S. Maney, with Mr. Ebertz serving as chairperson. The compensation committee monitors compliance with all federal and state statutes relating to employment and compensation, recommends to the board of directors compensation for officers, and approves our compensation program including benefits, stock option plans and stock ownership plans.

Our audit committee is comprised of Adil M. Ameer, David C. Ebertz, John R. Howard, Kay S. Jorgensen and Thomas J. Zeller, with Mr. Ameer serving as chairperson. The audit committee recommends to the board of directors an independent accounting firm to conduct our annual audit, reviews the scope and results of the annual audit including reports and recommendations of the firm, reviews our internal audit function, and periodically confers with the internal audit group, our management and our independent accountants.

Our nominating committee is comprised of Bruce B. Brundage, Kay S. Jorgensen, David S. Maney and Thomas J. Zeller, with Mr. Zeller serving as chairperson. The nominating committee recommends to the board of directors persons to be nominated as directors or to be elected to fill vacancies on the board. Our bylaws require that an outside director serve as chairperson of the committee.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

Our compensation committee is solely comprised of the following outside directors: Bruce B. Brundage, David C. Ebertz, Gerald R. Forsythe, John R. Howard, Kay S. Jorgensen and David S. Maney.

Mr. Forsythe is the owner of two companies providing services to Black Hills Energy Capital, one of our subsidiaries. Forsythe Building Fund leases an office building to Black Hills Energy Capital for approximately $8,200 per month and A&R Leasing leases vehicles to Black Hills Energy Capital for approximately $3,200 per month.

On March 15, 2001, Black Hills Power, Inc., one of our subsidiaries, began leasing 10 two megawatt mobile diesel electric generators from Indeck Power Equipment Co., which is controlled by Mr. Forsythe, for $250,000 per month in the aggregate. There is a separate lease for each generator with a lease term of March 15, 2001 through September 15, 2002. The leases, however, may be canceled on September 15, 2001 with a cancellation fee of $125,000 per generator.

On July 7, 2000, we completed the acquisition of Indeck Capital. Mr. Forsythe was the majority shareholder of Indeck. We issued approximately 1.54 million shares of our common stock and 4,000 shares of our convertible preferred stock to the shareholders of Indeck for a total consideration of approximately $38 million. In addition, we assumed approximately $40 million of debt. Additional consideration, consisting of our common stock and convertible preferred stock may be paid in the form of an earn-out over a four-year period. The earn-out is based on the acquired company's earnings during that period and cannot exceed $35 million in total. The purchase price was determined through arm's-length negotiations between us and the Indeck shareholders. The other shareholders of Indeck were Michelle R. Fawcett, Marsha Fournier, Monica Breslow, Melissa S. Forsythe and John W. Salyer, Jr. These individuals and Mr. Forsythe, as holders of our convertible preferred stock, are entitled to receive cumulative quarterly cash dividends at a rate equal to 1% per year computed on the basis of $1,000 per share plus an amount equal to any dividend payable with respect to our common stock.

CERTAIN TRANSACTIONS

Western Health, a division of Rapid City Regional Hospital, is a third party administrator for our healthcare plans. Adil M. Ameer, one of our directors, is President and Chief Executive Officer of Rapid City Regional Hospital. We paid approximately $103,000 to Western Health in 2000 for its services.

For additional disclosures with respect to transactions with related parties, see "--Compensation Committee Interlocks and Insider Participation."

DIRECTORS' FEES

Directors who are not also our officers or employees receive an annual fee of $15,500 plus a fee of $600 for each board meeting and committee attended, provided such committee meetings are substantive in nature and content.

In addition, each outside director receives common stock equivalents equal to $7,000 per year divided by the market price of our common stock on a specified date. The common stock equivalents are payable in stock or cash at retirement or can be deferred at the election of the director.

Members of our board of directors are required to beneficially own 100 shares of our common stock when they are initially elected a director and to apply at least 50% of his or her annual fees toward the purchase of additional shares until the director has accumulated at least 2,000 shares of our common stock.

EXECUTIVE COMPENSATION

SUMMARY COMPENSATION

The following table sets forth the compensation we paid to each of our five most highly compensated executive officers for 2000:

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL COMPENSATION SALARY	ANNUAL COMPENSATION BONUS(1)	LONG-TERM COMPENSATION SECURITIES UNDERLYING OPTIONS GRANTED	ALL OTHER COMPENSATION
Daniel P. Landguth.....................	2000	$314,800	$233,955	84,000	-0-
Chairman and Chief Executive	1999	262,600	127,350	23,500	-0-
Officer	1998	237,550	47,683	18,000	-0-
Everett E. Hoyt........................	2000	$191,200	$ 92,430	41,000	-0-
President and Chief Operating	1999	169,100	53,100	8,000	-0-
Officer	1998	158,100	18,135	7,500	-0-
Gary R. Fish...........................	2000	$190,050	$107,677	41,000	$4,025(2)
President and Chief Operating	1999	142,300	61,250	10,500	-0-
Officer of Independent Energy	1998	123,350	18,154	10,500	-0-
Mark T. Thies..........................	2000	$145,035	$ 81,000	30,000	$5,100(2)
Senior Vice President and Chief	1999	102,300	31,800	8,000	-0-
Financial Officer	1998	94,300	11,092	7,500	-0-
Thomas M. Ohlmacher....................	2000	$137,000	$269,750	30,000	$3,335(2)
Senior Vice President-Power Supply	1999	126,500	35,700	8,000	-0-
and Power Marketing	1998	112,350	12,825	7,500	-0-

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(1) Bonus amounts include amounts earned under the short-term annual incentive plan, a bonus program for our executive officers based on the attainment of predetermined profitability measures. Mr. Ohlmacher's bonus in 2000 includes a $200,000 energy marketing bonus.

(2) Represents our matching contributions to our 401(k) plan.

STOCK OPTION GRANTS IN 2000

The following table sets forth information with respect to options granted during 2000 to each of our five most highly compensated officers.

NAME	INDIVIDUAL GRANTS: NUMBER OF SECURITIES UNDERLYING OPTIONS GRANTED(1)	PERCENT OF TOTAL OPTIONS GRANTED TO EMPLOYEES IN FISCAL YEAR	EXERCISE PRICE PER SHARE	EXPIRATION DATE	GRANT DATE PRESENT VALUE(2)
Daniel P. Landguth......................	84,000	17.1%	$21.875	04/25/10	$220,080
Everett E. Hoyt.........................	41,000	8.3%	$21.875	04/25/10	$107,420
Gary R. Fish............................	41,000	8.3%	$21.875	04/25/10	$107,420
Mark T. Thies...........................	30,000	6.1%	$21.875	04/25/10	$ 78,600
Thomas M. Ohlmacher.....................	30,000	6.1%	$21.875	04/25/10	$ 78,600

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(1) Options vest annually in installments of 33% per year beginning on the first anniversary of the date of grant. All options become fully vested if a change in control occurs.

(2) We used the Black-Scholes option-pricing model to determine the present value of the options granted and made the following assumptions: an expected volatility of 20.14%; a 6.62% risk-free rate of return; a 4.2% dividend yield; and a 10-year exercise period.

AGGREGATED STOCK OPTION EXERCISES IN 2000 AND YEAR-END OPTION VALUES

The following table provides information on stock option exercises in 2000 by the named executive officers and the value of such officers' unexercised options at December 31, 2000:

NAME	SHARES ACQUIRED ON EXERCISE	VALUE REALIZED	NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS AT 12/31/00 EXERCISABLE/UNEXERCISABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS AT 12/31/00 EXERCISABLE/UNEXERCISABLE(1)
Daniel P. Landguth................	-0-	$0	93,433 / 71,667	$2,437,440 / $1,443,066
Everett E. Hoyt...................	-0-	$0	40,332 / 32,668	$1,036,623 / $ 680,439
Gary R. Fish......................	-0-	$0	47,166 / 34,334	$1,215,484 / $ 697,671
Mark T. Thies.....................	-0-	$0	27,666 / 25,334	$700,014 / $ 512,674
Thomas M. Ohlmacher...............	-0-	$0	36,666 / 25,334	$952,764 / $ 512,674

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(1) The value of unexercised options is the market value of the shares at year-end minus the exercise price.

RETIREMENT PLANS

We offer a tax-qualified defined benefit retirement plan for our employees. This pension plan provides benefits at retirement based on length of employment service and average monthly pay in the five consecutive calendar years of highest earnings out of the last 10 years. Our employees do not contribute to the plan. The amount of our annual contribution to the plan is based on an actuarial determination. Accrued benefits become 100% vested after an employee completes five years of service.

In 2000, we amended our retirement plan by decreasing future benefits while providing a matching contribution under our 401(k) plan in return. Our employees who were age 50 on or before December 31, 1999 made a one-time election to remain under the old plan or to accept lower benefits under the revised plan in return for 401(k) matching contributions.

We also offer a pension equalization plan. The pension equalization plan is a nonqualified supplemental plan in which benefits are not tax deductible until paid. The plan is designed to provide our higher paid executive employees a retirement benefit which, when added to social security benefits and the pension to be received under the defined benefit retirement plan, will approximate retirement benefits being paid by other employers to their employees in similar executive positions. The employee's pension payable from the qualified pension plan is limited under current law to $140,000 annually, and the compensation taken into account in determining contributions and benefits cannot exceed $170,000 and cannot include nonqualified deferred compensation. The amount of deferred compensation paid under nonqualified plans such as the pension equalization plan is not subject to these limits. A participant under the pension equalization plan does not qualify for benefits until the benefits become vested under a vesting schedule--20% after three years of employment under the plan, increasing up to 100% vesting after eight years of employment under the plan. No credit for past service is granted under the pension equalization plan. The annual benefit is 25% of the employee's average earnings, if salary was less than two times the Social Security wage base, or 30%, if the employee's salary was more than two times the Social Security wage base, multiplied by the vesting percentage. Average earnings are normally an employee's average earnings for the five highest consecutive full years of employment during the 10 full years of employment immediately preceding the year of calculation. The annual pension equalization plan benefit is paid on a monthly basis for 15 years to each participating employee and, if deceased, to the employee's designated beneficiary or estate, commencing at the earliest of death or when the employee is both retired and 62 years of age or more.

In the event that at the time of a participant's retirement, the participant's salary level exceeds the qualified pension plan annual compensation limitation of $170,000 or includes nonqualified deferred compensation, the participant will receive an additional benefit which is measured by the difference between the monthly benefit which would have been provided to the participant under the defined benefit retirement plan as if there were no annual compensation limitation and no exclusion on nonqualified deferred compensation, and the monthly benefit to be provided to the participant under the defined benefit retirement plan.

We amended the pension equalization plan, effective January 30, 2001, to compensate for the $140,000 annual defined benefit pension limitation. The additional benefit is equal to the difference between the monthly benefit which would have been provided to the participant under the defined benefit retirement plan as if there were no annual defined benefit pension limitation and the monthly benefit to be provided to the participant under the defined benefit retirement plan.

Participants in the pension equalization plan are designated by our board of directors upon recommendation of the Chief Executive Officer. Selection is based on key employees as determined by management and considerations of performance, rather than being based solely on salary. The minimum salary component applied in the selection process is the maximum annual Social Security taxable wage base that is presently $80,400.

RETIREMENT BENEFITS

The following table illustrates estimated annual benefits payable under the defined benefit retirement plan and the pension equalization plan to our employees who retire at the normal retirement date:

	YEARS OF SERVICE				
ANNUAL PAY	15 YEARS	20 YEARS	25 YEARS	30 YEARS	35 YEARS
$110,000	$ 51,464	$ 59,562	$ 67,660	$ 75,758	$ 83,856
125,000	58,769	68,067	77,365	86,663	95,961
150,000	70,944	82,242	93,540	104,838	116,136
175,000	91,869	105,167	118,465	131,763	145,061
200,000	105,294	120,592	135,890	151,188	166,486
225,000	118,719	136,017	153,315	170,613	187,911
250,000	132,144	151,442	170,740	190,038	209,336
275,000	145,569	166,867	188,165	209,463	230,761
300,000	158,994	182,292	205,590	228,888	252,186
350,000	185,844	213,142	240,440	267,738	295,036
400,000	212,694	243,992	275,290	306,588	337,886
450,000	239,544	274,842	310,140	345,438	380,736

The years of credited service under the defined benefit retirement plan for our five most highly compensated officers are as follows:

- Daniel P. Landguth, 31 years;

- Everett E. Hoyt, 26 years, subject to reduction for service from prior employment;

- Gary R. Fish, 14 years;

- Mark T. Thies, three years; and

- Thomas M. Ohlmacher, 26 years.

The benefits in the foregoing table were calculated as a straight life annuity. Amounts shown exclude Social Security benefits and include benefits from both the defined benefit retirement plan and from the pension equalization plan, assuming a 100% vested interest in the pension equalization plan.

SEVERANCE AGREEMENTS

We have entered into change of control severance agreements with each of our five most highly compensated executive officers and some of our other executive officers and key employees. The change of control severance agreements provide for specified payments and other benefits to be payable upon a change in control and a subsequent termination of employment, either involuntary or by the employee for a "good reason."

A "change in control" is defined in the agreements as:

- an acquisition of 30% or more of our common stock, except for certain defined acquisitions, such as acquisitions by employee benefit plans, us or any of our subsidiaries; or

- members of our incumbent board of directors at the time the agreements were executed cease to constitute at least two-thirds of the members of the board of directors, with the incumbent board of directors being defined as those individuals consisting of the board of directors on the date the agreement was executed and any other directors elected subsequently whose election was approved by the incumbent board of directors; or

- approval by our shareholders of:

    - a merger, consolidation, or reorganization;

    - a liquidation or dissolution; or

    - an agreement for the sale or other disposition of all or substantially all of our assets, with exceptions for transactions which do not involve an effective change in control of voting securities or board of directors membership, and transfers to subsidiaries or sales of subsidiaries.

A change in control will not be deemed to occur until all regulatory approvals required to effect a change in control have been obtained.

A "good reason" is defined in the agreements to include:

- a change in the executive's status, title, position or responsibilities;

- a reduction in the executive's annual compensation or any failure to pay the executive any compensation or benefits to which he or she is entitled within seven days of the date due;

- any material breach by us of any provisions of the change of control severance agreement;

- requiring the executive to be based outside a 50-mile radius from Rapid City, South Dakota; or

- our failure to obtain an agreement from any successor company to assume and agree to perform under the change of control severance agreement.

The agreement with Mr. Landguth also contains an "optional window period," a 30-day period of time beginning on the one-year anniversary after a change in control, during which time Mr. Landguth may resign for any reason and receive his full compensation payments and benefits.

Upon a change in control, our executives will have an employment contract for a three-year period, but not beyond age 65. During this employment term, each executive will receive annual compensation at least equal to the highest rate in effect at any time during the one-year period preceding the change in control and will also receive employment welfare benefits, pension benefits and supplemental retirement benefits on a basis no less favorable than those received prior to the change in control.

If an executive's employment is terminated during the three-year term involuntarily, for a "good reason," or, in the case of the Chief Executive Officer, for any reason during the "optional window period," that executive will be entitled to the following benefits:

- severance pay equal to 2.99 times the executive's five-year average taxable compensation for the remainder of the three-year employment term; and

- continuation of employee welfare benefits for the remainder of the employment term, with an offset for similar benefits received, along with additional credit for service under our pension equalization plan and our defined benefit retirement plan equal to the remainder of the employment term.

The change of control severance agreements contain a "cap" provision which reduces any amounts payable to an amount which would prevent any payments from being nondeductible under the Internal Revenue Code. The change of control severance agreements also provide for reimbursement of legal fees and expenses of the executive incurred by the executive after the change in control in seeking to obtain or enforce any benefits provided by the change of control severance agreement. Our executives are not required to mitigate the amount of any payment or benefit by seeking other employment or otherwise, and the payments or benefits are not reduced if our executive obtains other employment and/or benefits, except for employee welfare benefits.

PRINCIPAL SHAREHOLDERS

The following table sets forth the beneficial ownership of our common stock as of February 28, 2001 for:

- each person or entity known by us to beneficially own more than 5% of our outstanding shares of common stock;

- each of our directors and each of our executive officers named in the summary compensation table; and

- all of our directors and executive officers as a group.

Beneficial ownership includes shares a director or executive officer has the power to vote or transfer, and stock options that are exercisable currently or within 60 days of February 28, 2001.

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

NAME AND ADDRESS OF BENEFICIAL OWNER	SHARES OF COMMON STOCK BENEFICIALLY OWNED	OPTIONS EXERCISABLE WITHIN 60 DAYS	DIRECTORS' COMMON STOCK EQUIVALENTS(1)	TOTAL	PERCENTAGE(2)
DIRECTORS AND NAMED EXECUTIVE OFFICERS					
Adil M. Ameer	1,401(3)	-0-	910	2,311	*
Bruce B. Brundage	5,422(4)	-0-	6,381	11,803	*
David C. Ebertz	2,182(5)	-0-	638	2,820	*
Gary R. Fish	9,218(6)	47,166	-0-	56,384	*
Gerald R. Forsythe	1,029,577(7)	-0-	119	1,029,696	4.5%
John R. Howard	16,864	-0-	5,135	21,999	*
Everett E. Hoyt	12,289	40,332	-0-	52,621	*
Kay S. Jorgensen	2,967	-0-	2,015	4,982	*
Daniel P. Landguth	18,620	93,433	-0-	112,053	*
David S. Maney	1,438(8)	-0-	411	1,849	*
Thomas M. Ohlmacher	6,407(9)	36,666	-0-	43,073	*
Mark T. Thies	3,506(10)	27,666	-0-	31,172	*
Thomas J. Zeller	1,476(11)	-0-	910	2,386	*
All directors and executive officers as a group (19 persons)	1,137,293	379,043	16,519	1,532,855	6.7%
FIVE PERCENT SHAREHOLDERS					
Gerald R. Forsythe, Michelle R. Fawcett, et al, 1111 S. Willis Avenue, Wheeling, IL 60090	1,657,191(12)	-0-	119	1,657,310	7.2%
FMR Corp., 82 Devonshire Street, Boston, MA 02109	1,546,145(13)	-0-	-0-	1,546,145	6.7%

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* Represents less than 1% of the common stock outstanding.

(1) Represents common stock allocated to the directors' accounts in the directors' stock-based compensation plan, of which the trustee has sole voting and investment authority.

(2) Shares of common stock which were not outstanding but could be acquired by a person upon exercise of an option within sixty days of February 28, 2001, or conversion of the Series 2000-A Convertible Preferred Stock are deemed outstanding for the purpose of computing the percentage of outstanding shares beneficially owned by such person. Such shares, however, are not deemed

to be outstanding for the purpose of computing the percentage of outstanding shares beneficially owned by any other person.

(3) Includes 150 shares owned jointly with Mr. Ameer's spouse as to which he shares voting and investment authority.

(4) Includes 5,400 shares owned by the Brundage & Co. Pension Plan and Trust of which Mr. Brundage is the trustee with sole voting and investment authority.

(5) Shares owned jointly with Mr. Ebertz's spouse as to which he shares voting and investment authority.

(6) Includes 7,592 shares owned jointly with Mr. Fish's spouse as to which he shares voting and investment authority.

(7) Includes 11,400 shares owned by Indeck Power Equipment, Inc., which Mr. Forsythe controls, and 70,857 shares of common stock issuable upon conversion of 2,480 shares of Series 2000-A Preferred Stock, which are currently convertible at his option and which will be automatically converted on July 7, 2005. Does not include other shares of common stock that Mr. Forsythe may be deemed to beneficially own as a result of membership in a group. See Note 12 below for further information with respect to this group. Mr. Forsythe disclaims beneficial ownership of such other shares.

(8) Includes 1,000 shares owned jointly with Mr. Maney's spouse as to which he shares voting and investment authority.

(9) Includes 2,400 shares owned jointly with Mr. Ohlmacher's spouse as to which he shares voting and investment authority.

(10) Includes 3,106 shares owned jointly with Mr. Thies's spouse as to which he shares voting and investment authority.

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

(12) Represents shares held by the following individuals who became shareholders as a result of the Indeck Capital acquisition: Gerald R. Forsythe (1,029,696 shares), Michelle R. Fawcett (107,317 shares), Marsha Fournier (107,317 shares), Monica J. Breslow (107,428 shares), Melissa S. Forsythe (107,428 shares) and John W. Salyer, Jr. (198,124 shares). The shares include 114,286 shares of common stock issuable upon conversion of 4,000 shares of Series 2000-A Preferred Stock, which are currently convertible at their option and which will be automatically converted on July 7, 2005. Information relating to the shareholders is based on the shareholders' Schedule 13D dated July 5, 2000, Mr. Forsythe's Forms 3 and 4 filed with the Securities and Exchange Commission and our shareholder records. The Schedule 13D indicates that the shareholders may be deemed to be a group for purposes of the Securities Exchange Act of 1934. Each shareholder disclaims beneficial ownership of shares over which that shareholder does not have sole investment authority.

(13) As of December 31, 2000, (a) FMR Corp. had sole dispositive power with respect to all of these shares and sole voting power with respect to 1,045,405 of these shares, (b) Edward C. Johnson 3d, Chairman of FMR Corp., and Abigail P. Johnson, a Director of FMR Corp., each had sole dispositive power with respect to all of these shares, and (c) these shares represent (i) 500,740 shares beneficially owned by Fidelity Management & Research Company, a wholly-owned subsidiary of FMR Corp. ("Fidelity"), as a result of acting as investment adviser to various investment companies, (ii) 934,655 shares beneficially owned by Fidelity Management Trust Company, a wholly-owned subsidiary of FMR Corp., as a result of serving as investment manager of certain institutional accounts, and (iii) 110,750 shares beneficially owned by Fidelity International Limited, which is independent of FMR Corp. and Fidelity, as a result of investment advisory and management services and those 110,750 shares are included on a voluntary basis by

FMR Corp. Information relating to this shareholder is based on the shareholder's Schedule 13G dated February 14, 2001.

SHAREHOLDERS AGREEMENT

In connection with the Indeck Capital acquisition, we entered into a shareholders agreement with various new shareholders (namely, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Melissa S. Forsythe, Monica Breslow and John W. Salyer, Jr.) on June 30, 2000.

CORPORATE GOVERNANCE AND VOTING. Under the terms of the agreement, these shareholders have the right to nominate one director to our board of directors and one director to the boards of directors of each of our direct or indirect wholly-owned subsidiaries.

This right terminates:

- on any date before June 30, 2004 on which the new shareholders collectively own less than 5% of the shares of common stock (after giving effect to and assuming conversion of any shares of preferred stock owned by them) outstanding as of June 30, 2000;

- on any date after June 30, 2004 on which the new shareholders collectively own less that 5% of the shares of common stock (after giving effect to and assuming conversion of any shares of preferred stock owned by them) then outstanding; or

- in any event no later than the date of the annual meeting of shareholders in 2010.

GENERAL RESTRICTION ON TRANSFER. The shares acquired by the new shareholders in connection with the Indeck acquisition may not be sold, transferred, assigned or otherwise disposed of until June 30, 2002, either pursuant to Rule 144 under the Securities Act or otherwise, except as specifically permitted in the shareholders agreement.

STANDSTILL. Prior to June 30, 2004, the new shareholders may not, without the written consent of our board of directors, own any of our common stock or preferred stock other than:

- the shares of common stock and preferred stock the new shareholders acquired in connection with the Indeck acquisition;

- shares of common stock acquired as a result of the conversion of preferred stock acquired by the new shareholders in connection with the Indeck acquisition;

- shares of common stock or options for common stock acquired by a new shareholder who is an officer and/or director pursuant to an employee benefit plan; and

- shares of common stock or preferred stock acquired pursuant to any pro rata stock dividend, stock split, exchange, recapitalization, reclassification or other distribution.

From July 1, 2004, through June 30, 2010, the new shareholders may not, without the written consent of our board of directors, acquire any shares of common stock or preferred stock (other than the acquisition of shares in the manner specified above) if immediately following the acquisition of those shares, the new shareholders would own more than 9.9% of the then outstanding shares of common stock on a fully-diluted basis.

The new shareholders also may not, until June 30, 2010, take any action, either individually, as a group, or in concert with any other group, to acquire us or which involves the solicitation of proxies or any attempt to control or influence the board of directors. The new shareholders also may not transfer any shares of common stock or preferred stock to a person who holds or would hold following that transfer 5% or more of our then outstanding shares of common stock.

RIGHT OF FIRST OFFER. The new shareholders are required to notify our board of directors before a new shareholder transfers 500,000 shares or more of common stock. We then have the right to purchase those shares before any other person or entity.

DESCRIPTION OF CAPITAL STOCK

GENERAL

Our authorized capital stock consists of (a) 100,000,000 shares of common stock, having a par value of $1 per share, and (b) 25,000,000 shares of preferred stock, without par value. As of February 28, 2001, 22,951,394 shares of common stock and 4,000 shares of preferred stock were outstanding. Upon completion of this offering, we will have outstanding 25,951,394 shares of common stock, or 26,401,394 shares if the underwriters' over-allotment option is exercised in full.

COMMON STOCK

The holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of shareholders. Holders may use cumulative voting for the election of directors. Subject to preferences that may be applicable to any outstanding series of preferred stock, holders of common stock are entitled to receive equally dividends as they may be declared by our board of directors out of funds legally available for the payment of dividends. In the event of our liquidation or dissolution, holders of common stock are entitled to share equally in all assets remaining after payment of liabilities and the liquidation preference of any outstanding series of preferred stock.

Holders of common stock have no preemptive rights and have no rights to convert their common stock into any other securities. All of the outstanding shares of common stock are, and the shares of common stock we sell in this offering will be, duly authorized, validly issued, fully paid and nonassessable.

PREFERRED STOCK

Our board of directors has the authority, without further action by our shareholders, to issue shares of undesignated preferred stock from time to time in one or more series and to fix the related number of shares and the designations, voting powers, preferences, optional and other special rights, and restrictions or qualifications of that preferred stock. The rights, preferences, privileges and restrictions or qualifications of different series of preferred stock may differ from common stock and other series of preferred stock with respect to dividend rates, amounts payable on liquidation, voting rights, conversion rights, redemption provisions, sinking fund provisions and other matters. The issuance of additional series of preferred stock could:

- decrease the amount of earnings and assets available for distribution to holders of common stock;

- adversely affect the rights and powers, including voting rights, of holders of common stock; and

- have the effect of delaying, deferring or preventing a change in control.

NO PAR PREFERRED STOCK, SERIES 2000-A. We currently have 4,000 shares of No Par Preferred Stock, Series 2000-A issued and outstanding. The shares of preferred stock currently issued and outstanding are cumulative, convertible, no par shares and are non-voting except as generally discussed below or as otherwise required by law. The holders of our preferred stock are entitled to receive cumulative quarterly cash dividends at a rate equal to 1% per year computed on the basis of $1,000 per share plus an amount equal to any dividend payable with respect to our common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. Dividends on our preferred stock must be paid or declared and set apart for payment before any dividends may be paid or declared and set apart for payment on our common stock. In addition, no dividend may be declared or paid with respect to our common stock unless the same dividend is declared and paid with respect to our preferred stock.

We have the authority to redeem our preferred stock in whole or in part, at any time. The redemption price per share for the preferred stock is $1,000 plus all accrued and unpaid dividends. Each share of preferred stock is convertible at the option of the shareholder into shares of our common stock at any time prior to July 7, 2005 and, unless redeemed, will be automatically converted into shares of our common stock on July 7, 2005. Each share of preferred stock is convertible into 28.57 shares (the liquidation preference amount of $1,000 divided by the conversion price of $35.00 per share). Upon delivery to a shareholder of a notice of redemption, the conversion price will be adjusted to equal the lesser of the conversion price then in effect and the current market price of our common stock on the redemption notice date.

The holders of our preferred stock are not entitled to any right to vote at any meeting of our shareholders for the election of directors, except that whenever dividends accrued on the preferred stock remain unpaid in an amount equivalent to at least four quarterly dividends, but less than eight, the holders of the preferred stock, voting separately as one class for such purpose, will be entitled at the next succeeding annual meeting of shareholders to elect that number of directors as will constitute one-third of the then board members, and the holders of common stock will be entitled to elect the remaining directors. Whenever the accrued and unpaid dividends on the preferred stock become equivalent to or exceed eight quarterly dividends, the holders of the preferred stock, voting separately as one class for such purpose, will be entitled to elect at the next succeeding annual meeting of shareholders the smallest number of directors necessary to constitute a majority of our board, and the holders of common stock will be entitled to elect the remaining directors. After the accrued and unpaid dividends are paid, the holders of the preferred stock will be divested of these voting rights at the next succeeding annual meeting of shareholders.

We must obtain the consent of the holders of two-thirds of the outstanding shares of our preferred stock, voting separately as one class for such purpose, before we may:

- create or increase the authorized amount of any other class of stock which will rank prior to the preferred stock in respect of dividends or assets;

- reclassify shares of stock of any class ranking junior to the preferred stock in respect of dividends or assets, wholly or partially into shares of stock of any class ranking on a parity with or prior to the preferred stock in respect of dividends or assets;

- sell all or substantially all of our property and assets to, or merge or consolidate into or with, any other company; or

- make any distribution out of capital or capital surplus, other than dividends payable in stock ranking junior to the preferred stock in respect of dividends and assets, to holders of stock ranking junior to the preferred stock in respect of dividends or assets.

REGISTRATION RIGHTS

In conjunction with our acquisition of Indeck Capital in July 2000, we entered into a registration rights agreement with various new shareholders (namely, Gerald R. Forsythe, Michelle R. Fawcett, Marsha Fournier, Melissa S. Forsythe, Monica Breslow and John W. Salyer, Jr.). A total of 1,651,033 shares of common stock (assuming conversion of our outstanding shares of preferred stock into common stock) are currently covered by the registration rights agreement. In the event that the new shareholders receive additional shares of our common stock and convertible preferred stock pursuant to the earn-out provisions related to the acquisition of Indeck, the additional shares of common stock, including shares received upon conversion of preferred stock, will be covered by the registration rights agreement.

The registration rights granted under the registration rights agreement entitle the parties to demand, at any time after June 30, 2002, a total of three registrations of common stock, one of which can be a shelf registration. The parties also have "piggyback" registration rights, although they have no registration rights with respect to this offering. The registration rights agreement also contains customary provisions regarding the payment of expenses by us and mutual indemnification agreements between us and the new shareholders for securities law violations.

ANTI-TAKEOVER EFFECTS OF SOUTH DAKOTA LAW AND PROVISIONS OF OUR CHARTER AND BYLAWS

South Dakota law and our articles of incorporation and bylaws contain certain provisions that might be characterized as anti-takeover provisions. These provisions may make it more difficult to acquire control of us or remove our management.

CONTROL SHARE ACQUISITIONS. The control share acquisition provisions of the South Dakota Domestic Public Corporation Takeover Act provide generally that the shares of a publicly-held South Dakota corporation acquired by a person that exceed the thresholds of voting power described below will have the same voting rights as other shares of the same class or series only if approved by:

- the affirmative vote of the majority of all outstanding shares entitled to vote, including all shares held by the acquiring person; and

- the affirmative vote of the majority of all outstanding shares entitled to vote, excluding all interested shares.

Each time an acquiring person reaches a threshold, an election must be held as described above before the acquiring person will have any voting rights with respect to shares in excess of such threshold. The thresholds which require shareholder approval before voting powers are obtained with respect to shares acquired in excess of such thresholds are 20%, 33 1/3% and 50%, respectively. We have elected in our articles of incorporation not to be subject to these provisions of South Dakota law.

BUSINESS COMBINATIONS. We are subject to the provisions of Section 47-33-17 of the South Dakota Domestic Public Corporation Takeover Act. In general, Section 47-33-17 prohibits a publicly-held South Dakota corporation from engaging in a "business combination" with an "interested shareholder" for a period of four years after the date that the person became an interested shareholder unless the business combination or the transaction in which the person became an interested shareholder is approved in a prescribed manner. After the four-year period has elapsed, the business combination must still be approved, if not previously approved in the manner prescribed, by the affirmative vote of the holders of a majority of the outstanding voting shares exclusive, in some instances, of those shares beneficially owned by the interested shareholder. Generally, a "business combination" includes a merger, a transfer of 10% or more of the corporation's assets, the issuance or transfer of stock equal to 5% or more of the aggregate market value of all of the corporation's outstanding shares, the adoption of a plan of liquidation or dissolution, or other transaction resulting in a financial benefit to the interested shareholder. Generally, an "interested shareholder" is a person who, together with affiliates and associates, owns 10% or more of the corporation's voting stock. This provision may delay, defer or prevent a change in control of us without the shareholders taking further action.

The South Dakota Domestic Public Corporation Takeover Act further provides that our board, in determining whether to approve a merger or other change of control, may take into account both the long-term as well as short-term interests of us and our shareholders, the effect on our employees, customers, creditors and suppliers, the effect upon the community in which we operate and the effect on the economy of the state and nation. This provision may permit our board to vote against some proposals that, in the absence of this provision, it would have a fiduciary duty to approve.

FAIR PRICE PROVISION. Our articles of incorporation require the affirmative vote of the holders of 80% or more of the outstanding shares of our voting stock to approve any "business transaction" with any "related person" or any "business transaction" in which a "related person" has an interest. However, if a majority of the members of our board who are not affiliated with the related party approve the business transaction, or if the cash or fair market value of any consideration received by our shareholders pursuant to a business transaction meets certain enumerated requirements, then the 80% voting requirement will not be applicable. Generally, our articles of incorporation define a "business transaction" to include a merger, asset or stock sale. Our articles of incorporation define a "related person" as any person or entity that owns 10% or more of our outstanding voting stock. The likely effect of this provision is to delay, defer or prevent a change in control of us.

BOARD COMPOSITION. Our articles of incorporation and bylaws provide for a staggered board of directors divided into three classes, with the term of office of one class expiring each year. Our articles of incorporation and bylaws also provide that our directors may be removed only for cause and by the affirmative vote of the majority of the remaining members of the board of directors. The likely effect of our staggered board of directors and the limitation on the removal of directors is an increase in the time required for the shareholders to change the composition of our board of directors.

AUTHORIZED BUT UNISSUED SHARES. The authorized but unissued shares of our common stock and preferred stock are available for future issuance without shareholder approval. These additional shares may be used for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. The existence of authorized but unissued and unreserved common stock and preferred stock could also render more difficult or discourage an attempt to obtain control of us by means of a proxy contest, tender offer, merger or otherwise.

Our board of directors has no present intention to issue any new series of preferred stock; however, our board has the authority, without further shareholder approval, to issue one or more series of preferred stock that could, depending on the terms of the series, either impede or facilitate the completion of a merger, tender offer or other takeover attempt. Although our board of directors is required to make any determination to issue such stock based on its judgment as to the best interest of our shareholders, our board could act in a manner that would discourage an acquisition attempt or other transaction that some, or a majority, of the shareholders might believe to be in their best interests or in which shareholders might receive a premium for their stock over the then market price of such stock. Our board of directors does not intend to seek shareholder approval prior to any issuance of preferred stock, unless otherwise required by law or the rules of the stock exchange on which our common stock is listed.

SHAREHOLDER ACTION BY WRITTEN CONSENT MUST BE UNANIMOUS. South Dakota law provides that any action which may be taken at a meeting of shareholders may be taken without a meeting if a written consent, setting forth the action taken, is signed by all of the shareholders entitled to vote with respect to the action taken. This provision prevents holders of less than all of our common stock from unilaterally using the written consent procedure to take shareholder action.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common stock is Wells Fargo Shareowner Services.

UNITED STATES FEDERAL TAX CONSIDERATIONS FOR NON-U.S. HOLDERS

The following discussion is a general discussion of the material U.S. federal income and estate tax consequences of the ownership and disposition of our common stock by a beneficial owner that is a "non-U.S. holder."

For purposes of this discussion, a non-U.S. holder is any person or entity other than:

- a citizen or resident of the United States;

- a partnership, corporation or other entity created or organized in or under the laws of the United States or of any political subdivision thereof;

- a trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust or the trust has a valid election in effect under applicable U.S. Treasury regulations to be treated as a U.S. person; or

- an estate, the income of which is includible in gross income for U.S. income tax purposes regardless of its source.

This discussion is based on the Internal Revenue Code of 1986, as amended, and administrative interpretations as of the date of this prospectus, all of which are subject to change, including changes with retroactive effect. This discussion does not address all aspects of U.S. federal income and estate taxation that may be relevant to non-U.S. holders in light of their particular circumstances and does not address any tax consequences arising under the laws of any state, local or foreign jurisdiction. Prospective holders should consult their tax advisors with respect to the particular tax consequences to them of owning and disposing of common stock.

DIVIDENDS

Dividends paid to a non-U.S. holder of common stock generally will be subject to withholding of United States federal income tax at a 30% rate or a reduced rate specified by an applicable income tax treaty. To obtain a reduced rate of withholding for dividends paid, a non-U.S. holder will be required to provide us with an Internal Revenue Service Form W-8BEN certifying its entitlement to benefits under a treaty. In addition, in certain cases where dividends are paid to a non-U.S. holder that is a partnership or other pass-through entity, persons holding an interest in the entity will need to provide us with the required certification. For example, an individual non-U.S. holder who holds through a non-U.S. partnership will be required to provide us with an Internal Revenue Service Form W-8BEN.

The withholding of U.S. federal income tax does not apply to dividends paid to a non-U.S. holder that provides an Internal Revenue Service Form W-8ECI, certifying that the dividends are effectively connected with the non-U.S. holder's conduct of a trade or business within the United States. Instead, the effectively connected dividends will be subject to regular U.S. income tax as if the non-U.S. holder were a U.S. resident. A non-U.S. corporation receiving effectively connected dividends may also be subject to an additional "branch profits tax" imposed at a rate of 30% (or a lower treaty rate) on an earnings amount that is net of the regular tax.

GAIN ON DISPOSITION OF COMMON STOCK

A non-U.S. holder generally will not be subject to U.S. federal income tax on gain realized on a sale or other disposition of common stock unless:

- the gain is effectively connected with a trade or business of the non-U.S. holder in the United States, or where a treaty applies, is attributable to a United States permanent establishment of the non-U.S. holder;

- in the case of certain non-U.S. holders who are non-resident alien individuals and hold the common stock as a capital asset, the individuals are present in the United States for 183 or more days in the taxable year of the disposition and meet other requirements; or

- the non-U.S. holder is subject to tax under the provisions of the Internal Revenue Code regarding the taxation of U.S. expatriates.

In addition, if we are or have been a "United States real property holding corporation" for U.S. federal income tax purposes, a non-U.S. holder who is otherwise not subject to U.S. federal income tax on gain realized on a sale or other disposition of common stock (as discussed above) would not be subject to such taxation, but only if our common stock continues to be "regularly traded on an established securities market" for U.S. federal income tax purposes and such non-U.S. holder does not own, directly or indirectly, at any time during the five-year period ending on the date of disposition or such shorter period the shares were held, more than five percent of the outstanding common stock. Our common stock currently is regularly traded for this purpose. We currently believe that we are a United States real property holding corporation for U.S. federal income tax purposes. A non-U.S. holder who owns, directly or indirectly, more than five percent of the common stock (as described above) would be subject to U.S. federal income tax on a sale or other disposition of common stock.

INFORMATION REPORTING REQUIREMENTS AND BACKUP WITHHOLDING

We must report annually to the Internal Revenue Service the amount of dividends paid to each non-U.S. holder, the name and address of the recipient, and the amount of any tax withheld. A similar report is sent to the non-U.S. holder. Under tax treaties or other agreements, the Internal Revenue Service may make its reports available to tax authorities in the recipient's country of residence. A non-U.S. holder must certify its non-U.S. status to avoid backup withholding at a 31% rate on dividends. Generally a non-U.S. holder will provide this certification on Internal Revenue Service Form W-8BEN.

U.S. information reporting and backup withholding generally will not apply to a payment of proceeds of a disposition of common stock where the transaction is effected outside the United States through a non-U.S. office of a non-U.S. broker. However, a non-U.S. holder must certify its non-U.S. status to avoid information reporting and backup withholding at a 31% rate on disposition proceeds where the transaction is effected by or through a U.S. office of a broker. In addition, U.S. information reporting requirements generally will apply to the proceeds of a disposition effected by or through a non-U.S. office of a U.S. broker, or by a non-U.S. broker with specified connections to the United States.

Backup withholding is not an additional tax. Rather, the tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. When withholding results in an overpayment of taxes, a refund may be obtained if the required information is furnished to the Internal Revenue Service.

FEDERAL ESTATE TAX

An individual non-U.S. holder who is treated as the owner of, or has made certain lifetime transfers of, an interest in the common stock will be required to include the value of the stock in the individual's gross estate for U.S. federal estate tax purposes, and may be subject to U.S. federal estate tax unless an applicable estate tax treaty provides otherwise.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated April 18, 2001, we have agreed to sell to the underwriters named below, for whom Credit Suisse First Boston Corporation, Lehman Brothers Inc., CIBC World Markets Corp. and UBS Warburg LLC are acting as representatives, the following respective numbers of shares of common stock:

UNDERWRITER	NUMBER OF SHARES
Credit Suisse First Boston Corporation	939,750
Lehman Brothers Inc.	671,250
CIBC World Markets Corp.	537,000
UBS Warburg LLC	537,000
ABN AMRO Rothschild LLC	30,000
Robert W. Baird & Co. Incorporated	15,000
Dain Rauscher Incorporated	30,000
D.A. Davidson & Co.	15,000
A.G. Edwards & Sons, Inc.	30,000
Invemed Associates LLC	30,000
Edward D. Jones & Co., L.P.	15,000
NatCity Investments, Inc.	15,000
Prudential Securities Incorporated	30,000
Raymond James & Associates, Inc.	15,000
Sanders Morris Harris	15,000
Scotia Capital (USA) Inc.	30,000
U.S. Bancorp Piper Jaffray Inc.	30,000
Wells Fargo Van Kasper, LLC	15,000
Total	3,000,000

The underwriting agreement provides that the underwriters are obligated to purchase all the shares of common stock in the offering if any are purchased, other than those shares covered by the over-allotment option described below. The underwriting agreement also provides that if an underwriter defaults the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated.

We have granted to the underwriters a 30-day option to purchase on a pro rata basis up to 450,000 additional shares from us and at the public offering price less the underwriting discounts and commissions. The option may be exercised only to cover any over-allotments of common stock.

The underwriters propose to offer the shares of common stock initially at the public offering price on the cover page of this prospectus and to selling group members at that price less a selling concession of $1.72 per share. The underwriters and selling group members may allow a discount of $0.10 per share on sales to other broker/dealers. After the public offering, the public offering price and concession and discount to broker/dealers may be changed by the representatives.

The following table summarizes the compensation and estimated expenses we will pay:

	PER SHARE		TOTAL	
	WITHOUT OVER-ALLOTMENT	WITH OVER-ALLOTMENT	WITHOUT OVER-ALLOTMENT	WITH OVER-ALLOTMENT
Underwriting discounts and commissions paid by us	$2.86	$2.86	$8,580,000	$9,867,000
Expenses payable by us	$0.34	$0.30	$1,025,000	$1,025,000

The offering is being made in compliance with the requirements of Rule 2710(c)(8) of the Conduct Rules of the National Association of Securities Dealers, Inc.

We have agreed that we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the Securities and Exchange Commission a registration statement under the Securities Act of 1933 relating to, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any such offer, sale, pledge, disposition or filing, without the prior written consent of Credit Suisse First Boston Corporation for a period of 90 days after the date of this prospectus, except (a) issuances pursuant to the exercise of employee stock options currently outstanding or subsequently granted pursuant to the terms of a plan in effect on the date hereof or pursuant to our dividend reinvestment plan, our employee stock purchase plan, our retirement savings plan or our non-qualified deferred compensation plan, (b) the registration of shares reserved for issuance under our omnibus incentive compensation plan and (c) issuances to the former shareholders of Indeck Capital pursuant to the earn-out provisions contained in the merger agreement, dated as of January 1, 2000, among us, Indeck and the former shareholders of Indeck.

Our officers and directors have agreed that they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction which would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any offer, sale, pledge or disposition, or to enter into any transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of Credit Suisse First Boston Corporation for a period of 90 days after the date of this prospectus.

We have agreed to indemnify the underwriters against liabilities under the Securities Act, or contribute to payments that the underwriters may be required to make in that respect.

In connection with the offering the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Over-allotment involves sales by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of shares over-allotted by the underwriters is not greater than the number of shares that they may purchase in the over-allotment option. In a naked short position, the number of shares involved is greater than the number of shares in the over-allotment option. The underwriters may close out any short position by either exercising their over-allotment option and/or purchasing shares in the open market.

- Syndicate covering transactions involve purchase of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the over-allotment option. If the underwriters sell more shares than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on The New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

A prospectus in electronic format may be made available on the web sites maintained by one or more of the underwriters participating in this offering. The representatives may agree to allocate a number of shares to underwriters for sale to their online brokerage account holders. Credit Suisse First Boston Corporation may effect an on-line distribution through its affiliate, CSFBDIRECT, Inc., an on-line broker dealer, as a selling group member. Internet distributions will be allocated by the underwriters that will make internet distributions on the same basis as other allocations.

Some of the underwriters or their affiliates have provided, and may in the future provide, commercial banking, investment banking and other services to us.

NOTICE TO CANADIAN RESIDENTS

RESALE RESTRICTIONS

The distribution of the common stock in Canada is being made only on a private placement basis exempt from the requirement that we prepare and file a prospectus with the securities regulatory authorities in each province where trades of common stock are made. Any resale of the common stock in Canada must be made under applicable securities laws which will vary depending on the relevant jurisdiction, and which may require resales to be made under available statutory exemptions or under a discretionary exemption granted by the applicable Canadian securities regulatory authority. Purchasers are advised to seek legal advice prior to any resale of the common stock.

REPRESENTATIONS OF PURCHASERS

By purchasing common stock in Canada and accepting a purchase confirmation a purchaser is representing to us and the dealer from whom the purchase confirmation is received that:

- the purchaser is entitled under applicable provincial securities laws to purchase the common stock without the benefit of a prospectus qualified under those securities laws,

- where required by law, that the purchaser is purchasing as principal and not as agent, and

- the purchaser has reviewed the text above under "--Resale Restrictions."

RIGHTS OF ACTION (ONTARIO PURCHASERS)

The securities being offered are those of a foreign issuer and Ontario purchasers will not receive the contractual right of action prescribed by Ontario securities law. As a result, Ontario purchasers must rely on other remedies that may be available, including common law rights of action for damages or rescission or rights of action under the civil liability provisions of the U.S. federal securities laws.

ENFORCEMENT OF LEGAL RIGHTS

All of the issuer's directors and officers as well as the experts named herein may be located outside of Canada and, as a result, it may not be possible for Canadian purchasers to effect service of process within Canada upon the issuer or such persons. All or a substantial portion of the assets of the issuer and such persons may be located outside of Canada and, as a result, it may not be possible to satisfy a judgment against the issuer or such persons in Canada or to enforce a judgment obtained in Canadian courts against such issuer or persons outside of Canada.

NOTICE TO BRITISH COLUMBIA RESIDENTS

A purchaser of common stock to whom the SECURITIES ACT (British Columbia) applies is advised that the purchaser is required to file with the British Columbia Securities Commission a report within ten days of the sale of any common stock acquired by the purchaser pursuant to this offering. The report must be in the form attached to British Columbia Securities Commission Blanket Order BOR #95/17, a copy of which may be obtained from us. Only one report must be filed for common stock acquired on the same date and under the same prospectus exemption.

TAXATION AND ELIGIBILITY FOR INVESTMENT

Canadian purchasers of common stock should consult their own legal and tax advisors with respect to the tax consequences of an investment in the common stock in their particular circumstances and about the eligibility of the common stock for investment by the purchaser under relevant Canadian legislation.

LEGAL OPINIONS

Morrill Thomas Nooney & Braun, LLP, Rapid City, South Dakota, will issue an opinion for us regarding the validity of the shares of common stock being offered. Certain legal matters will be passed on for us by Conner & Winters, A Professional Corporation, Tulsa, Oklahoma, and for the underwriters by Skadden, Arps, Slate, Meagher & Flom LLP, New York, New York.

EXPERTS

The audited financial statements of Black Hills Corporation included in this prospectus have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report with respect thereto, and are included herein in reliance upon the authority of said firm as experts in giving said report.

The audited financial statements of Indeck Capital, Inc. and Subsidiaries, Indeck North American Power Fund, L.P., Indeck North American Power Partners, L.P., Northern Electric Power Co., L.P. and South Glen Falls Limited Partnership as of December 31, 1999 and for the year ended December 31, 1999 included in this prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

In its report with respect to Indeck Capital, Inc. and Subsidiaries, it states that with respect to EIF Investors, Inc., a wholly-owned subsidiary of Indeck Capital, Inc., its opinion is based on the reports of other independent public accountants, namely Arthur Andersen LLP.

The estimated reserve evaluations of Ralph E. Davis Associates, Inc. for Black Hills Exploration and Production, Inc. at December 31, 2000, included in this prospectus, have been included in reliance on the firm's authority as experts in petroleum engineering.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the SEC. You may read and copy any reports, statements or other information we file at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549, or at the SEC's public reference rooms in New York, New York, and Chicago, Illinois. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms. Our filings with the SEC are also available to the public from the SEC's web site at HTTP://WWW.SEC.GOV. Our reports, proxy statements and other information filed with the SEC can also be inspected at the New York Stock Exchange, 20 Broad Street, New York, New York.

We have filed with the SEC a registration statement on Form S-1, including all amendments and exhibits to the registration statement, under the Securities Act with respect to the common stock to be sold in this offering. This prospectus constitutes a part of that registration statement. As allowed by the rules and regulations of the SEC, this prospectus does not contain all the information you can find in the registration statement and the exhibits to the registration statement. For further information with respect to us and the common stock offered in this offering, you should refer to the registration statement, including its exhibits. Furthermore, the statements contained in this prospectus concerning any document filed as an exhibit are not necessarily complete and, in each instance, we refer you to a copy of such document filed as an exhibit to the registration statement.

INDEX TO FINANCIAL STATEMENTS

PRO FORMA CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

The Unaudited Pro Forma Consolidated Condensed Statement of Income of Black Hills Corporation (the "Company") for the fiscal year ended December 31, 2000, has been prepared to illustrate the estimated effect of the Indeck Capital, Inc. ("Indeck"), Indeck North American Power Fund, L.P. ("INAPF"), Indeck North American Power Partners, L.P. ("INAPP"), Northern Electric Power Company, L.P. ("NEPCO"), and South Glens Falls, L.P. ("SGF") transactions (collectively "the Transactions") described in Note 14 to the Company's notes to consolidated financial statements included elsewhere in this prospectus. The Pro Forma Statement of Income gives pro forma effect to the Transactions as if they had occurred on January 1, 2000.

The accompanying pro forma information is presented for illustrative purposes only and is not necessarily indicative of the results of operations which would actually have been reported had the Transactions been in effect during the period presented, or which may be reported in the future.

The accompanying Unaudited Pro Forma Consolidated Condensed Statement of Income should be read in conjunction with the historical financial statements and related notes thereto for the Company, Indeck, INAPF, INAPP, NEPCO and SGF included elsewhere in this prospectus.

BLACK HILLS CORPORATION
UNAUDITED PRO FORMA CONSOLIDATED CONDENSED STATEMENT OF INCOME
FOR THE YEAR ENDED DECEMBER 31, 2000

(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	12/31/00 COMPANY CONSOLIDATED	YTD THRU 6/30/00 INDECK	YTD THRU 6/30/00 INAPF	YTD THRU 6/30/00 INAPP
REVENUES				
Operating revenues	$1,623,836	$ 7,351	$ 2,102	$ 896
Equity in income of unconsolidated affiliates	--	4,643	4,231	42
TOTAL REVENUES	1,623,836	11,994	6,333	938
OPERATING EXPENSES				
Fuel and purchased power expense	1,370,841	--	--	--
Operations and maintenance	46,054	3,828	2,045	--
Administrative and general	44,423	2,607	950	910
Depreciation, depletion and amortization	32,864	280	--	--
Taxes other than income	14,904	230	--	--
TOTAL OPERATING EXPENSES	1,509,086	6,945	2,995	910
INCOME FROM OPERATIONS	114,750	5,049	3,338	28
OTHER INCOME (EXPENSES)				
Other, net	2,996	35	--	--
Interest income	7,075	72	--	--
Interest expense	(30,342)	(3,019)	--	--
TOTAL OTHER INCOME (EXPENSES)	(20,271)	(2,912)	--	--
INCOME (LOSS) BEFORE INCOME TAXES AND MINORITY INTEREST	94,479	2,137	3,338	28
Minority interest	(11,273)	(5)	(42)	--
Income tax (expense) benefit	(30,358)	(881)	--	--
NET INCOME (LOSS)	52,848	1,251	3,296	28
Preferred stock dividends	(78)	--	--	--
NET INCOME (LOSS) AVAILABLE FOR COMMON STOCK	$ 52,770	$ 1,251	$ 3,296	$ 28
Earnings per share: basic	$ 2.39			
Earnings per share: diluted	$ 2.37			
Weighted average common share outstanding: basic	22,118			
Weighted average common share outstanding: diluted	22,281			

(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	YTD THRU 12/31/00 NEPCO	YTD THRU 12/31/00 SGF	ADJUSTMENTS	YTD PRO FORMA 12/31/00
REVENUES				
Operating revenues	$ 20,907	$ 7,401	$ --	$1,662,493
Equity in income of unconsolidated affiliates	--	--	(2,558)(a)	6,358
TOTAL REVENUES	20,907	7,401	(2,558)	1,668,851
OPERATING EXPENSES				
Fuel and purchased power expense	--	--	--	1,370,841
Operations and maintenance	2,024	664	--	54,615
Administrative and general	3,764	1,542	--	54,196
Depreciation, depletion and amortization	--	--	1,868 (b)	35,012
Taxes other than income	--	--	--	15,134
TOTAL OPERATING EXPENSES	5,788	2,206	1,868	1,529,798
INCOME FROM OPERATIONS	15,119	5,195	(4,426)	139,053
OTHER INCOME (EXPENSES)				
Other, net	133	53	--	3,217
Interest income	--	--	(2,922)(c)	4,225
Interest expense	(7,618)	(2,235)	2,922 (c)	(40,292)

TOTAL OTHER INCOME (EXPENSES)	(7,485)	(2,182)	--	(32,850)
INCOME (LOSS) BEFORE INCOME TAXES AND MINORITY INTEREST	7,634	3,013	(4,426)	106,203
Minority interest	--	--	(2,919)(d)	(14,239)
Income tax (expense) benefit	--	--	(3,019)(e)	(34,258)
NET INCOME (LOSS)	7,634	3,013	(10,364)	57,706
Preferred stock dividends	--	--	(86)(f)	(164)
NET INCOME (LOSS) AVAILABLE FOR COMMON STOCK	$ 7,634	$ 3,013	$ (10,450)	$ 57,542
Earnings per share: basic				$ 2.47
Earnings per share: diluted				$ 2.45
Weighted average common share outstanding: basic			1,175(g)	23,293
Weighted average common share outstanding: diluted			1,262(g),(h)	23,543

NOTES TO THE UNAUDITED PRO FORMA CONSOLIDATED CONDENSED STATEMENT OF INCOME

NOTE 1:

For the purpose of the Pro Forma Consolidated Condensed Statement of Income for the fiscal year ended December 31, 2000, Condensed Statements of Income for the six month period ended June 30, 2000 have been included for Indeck, INAPF and INAPP. The six month period for these companies combined with their results of operations for the six month period ended December 31, 2000, as consolidated into the Company's December 31, 2000 Consolidated Income Statement, give effect to the fiscal year ended December 31, 2000 for pro forma presentation.

NOTE 2:

The following is a description of each of the pro forma adjustments:

(a) Eliminate the earnings in INAPF, INAPP, NEPCO and SGF recorded under the equity method of accounting.

(b) Additional depreciation and amortization expense resulting from fair value adjustments of depreciable assets and goodwill related to the acquisitions.

(c) Elimination of interest on loans between the Company and Indeck.

(d) Adjust the minority interest in earnings on a pro forma basis.

(e) Related tax effect of adjustments (a), (b) and (d).

(f) Additional preferred stock dividends on the shares issued in the Indeck acquisition.

(g) Additional weighted-average shares outstanding for common stock issued in the Indeck acquisition.

(h) Effect on the diluted weighted average shares for the conversion of preferred shares issued in the Indeck acquisition.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders of Black Hills Corporation:

We have audited the accompanying consolidated balance sheets of Black Hills Corporation (a South Dakota corporation) and Subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, common stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Black Hills Corporation and Subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Minneapolis, Minnesota,
January 26, 2001

BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED DECEMBER 31,	2000	1999	1998
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Operating revenues	$1,623,836	$791,875	$679,254
Operating expenses:			
Fuel and purchased power	1,370,841	637,302	531,518
Operations and maintenance	46,054	36,463	32,701
Administrative and general	44,423	18,272	15,747
Depreciation, depletion and amortization	32,864	25,067	24,037
Oil and gas ceilings test write down	--	--	13,546
Taxes, other than income taxes	14,904	12,880	12,472
	1,509,086	729,984	630,021
Operating income	114,750	61,891	49,233
Other income (expense):			
Interest expense	(30,342)	(15,460)	(14,707)
Interest income	7,075	3,614	2,861
Other, net	2,996	876	129
	(20,271)	(10,970)	(11,717)
Income before minority interest and income taxes	94,479	50,921	37,516
Minority interest	(11,273)	1,935	--
Income taxes	(30,358)	(15,789)	(11,708)
Net income	52,848	37,067	25,808
Preferred stock dividends	(78)	--	--
Net income available for common stock	$ 52,770	$ 37,067	$ 25,808
Earnings per share of common stock:			
Basic	$ 2.39	$ 1.73	$ 1.19
Diluted	$ 2.37	$ 1.73	$ 1.19
Weighted average common shares outstanding:			
Basic	22,118	21,445	21,623
Diluted	22,281	21,482	21,665

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

BLACK HILLS CORPORATION

CONSOLIDATED BALANCE SHEETS

AT DECEMBER 31,	2000	1999
	(IN THOUSANDS, EXCEPT SHARE AMOUNTS)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24,913	$ 16,482
Securities available for sale	2,113	7,586
Receivables (net of allowance for doubtful accounts of $3,631 and $278, respectively) -		
Customers	278,436	84,331
Other	21,283	55,694
Materials, supplies and fuel	16,545	14,278
Prepaid expenses	7,428	2,828
Derivatives at market value	68,292	5,158
	419,010	186,357
Investments	63,965	10,444
Property and equipment	1,072,129	700,044
Less accumulated depreciation and depletion	(277,848)	(246,299)
	794,281	453,745
Other assets:		
Regulatory asset	4,134	3,944
Other, principally goodwill	38,930	14,002
	43,064	17,946
	$1,320,320	$ 668,492
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 13,960	$ 1,330
Notes payable	211,679	97,579
Accounts payable	247,596	80,355
Accrued liabilities	49,661	26,088
Derivatives at market value	65,960	5,158
	588,856	210,510
Long-term debt, net of current maturities	307,092	160,700
Deferred credits and other liabilities:		
Investment tax credits	2,530	3,022
Federal income taxes	62,679	47,668
Reclamation and regulatory liability	22,340	22,494
Other	16,516	7,492
	104,065	80,676
Minority interest in subsidiaries	37,961	--
Commitments and contingencies (Notes 10, 11 and 14)		
Stockholders' equity:		
Preferred stock--no par Series 2000-A; 21,500 shares authorized; Issued and outstanding: 4,000 shares in 2000, -0- shares in 1999	4,000	--
Common stock equity--		
Common stock $1 par value; 100,000,000 shares authorized; Issued: 23,302,111 shares in 2000 and 21,739,030 shares in 1999	23,302	21,739
Additional paid-in capital	73,442	40,658
Retained earnings	191,482	162,239
Treasury stock	(9,067)	(8,030)
Accumulated other comprehensive income (loss)	(813)	--
	278,346	216,606
Total stockholders' equity	282,346	216,606
	$1,320,320	$ 668,492

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

BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31,	2000	1999	1998
	(IN THOUSANDS)		
Operating activities:			
Net income available for common	$ 52,770	$ 37,067	$ 25,808
Principal non-cash items-			
Depreciation, depletion and amortization	32,864	25,067	24,037
Oil and gas ceilings test write down	--	--	13,546
Derivative fair value adjustment	(2,332)	--	--
Gain on sales of assets	(3,736)	(2,541)	--
Deferred income taxes and investment tax credits	1,937	2,291	(2,535)
Minority interest	11,273	(1,935)	--
Change in operating assets and liabilities-			
Accounts receivable	(201,309)	2,232	(46,821)
Materials, supplies, fuel and other current assets	(3,513)	(4,003)	(2,954)
Accounts payable	165,394	6,268	41,465
Accrued liabilities	18,678	4,013	2,244
Other, net	2,444	5,284	(60)
	74,470	73,743	54,730
Investing activities:			
Property additions	(134,855)	(102,290)	(25,265)
Increase in investments	(13,646)	(52,319)	(1,960)
Payment for acquisition of net assets, net of cash acquired	(28,688)	--	--
Proceeds from sales of assets	5,500	3,463	--
Available for sale securities purchased	--	(7,870)	(22,361)
Available for sale securities sold	4,660	22,959	13,655
	(167,029)	(136,057)	(35,931)
Financing activities:			
Dividends paid	(23,527)	(22,602)	(21,737)
Treasury stock purchased	(1,037)	(4,949)	(3,081)
Common stock issued	3,854	424	273
Increase in short-term borrowings	73,848	92,489	5,067
Long-term debt--issuance	60,082	--	--
Long-term debt--repayments	(1,330)	(1,330)	(1,331)
Subsidiary distributions to minority interests	(10,900)	--	--
	100,990	64,032	(20,809)
Increase (decrease) in cash and cash equivalents	8,431	1,718	(2,010)
Cash and cash equivalents:			
Beginning of year	16,482	14,764	16,774
End of year	$ 24,913	$ 16,482	$ 14,764
Supplemental disclosure of cash flow information:			
Cash paid during the period for-			
Interest	$ 31,309	$ 18,819	$ 14,742
Income taxes	$ 18,518	$ 13,173	$ 13,135
Non cash net assets acquired through issuance of common and preferred stock (Note 14)	$ 34,493	$ --	$ --

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

BLACK HILLS CORPORATION

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	COMMON STOCK		ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	TREASURY STOCK		ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL
	SHARES	AMOUNT			SHARES	AMOUNT		
	(IN THOUSANDS)							
BALANCE AT DECEMBER 31, 1997	21,705	$21,705	$39,995	$143,703	--	$ --	$ --	$205,403
Comprehensive Income:								
Net income	--	--	--	25,808	--	--	--	25,808
	--	--	--	25,808	--	--	--	25,808
Dividends on common stock	--	--	--	(21,737)	--	--	--	(21,737)
Issuance of common stock	14	14	259	--	--	--	--	273
Treasury stock acquired, net	--	--	--	--	(141)	(3,081)	--	(3,081)
BALANCE AT DECEMBER 31, 1998	21,719	21,719	40,254	147,774	(141)	(3,081)	$ --	$206,666
Comprehensive Income:								
Net income	--	--	--	37,067	--	--	--	37,067
	--	--	--	37,067	--	--	--	37,067
Dividends on common stock	--	--	--	(22,602)	--	--	--	(22,602)
Issuance of common stock	20	20	404	--	--	--	--	424
Treasury stock acquired, net	--	--	--	--	(227)	(4,949)	--	(4,949)
BALANCE AT DECEMBER 31, 1999	21,739	21,739	40,658	162,239	(368)	(8,030)	$ --	$216,606
Comprehensive Income:								
Net income	--	--	--	52,848	--	--	--	52,848
Unrealized loss on available for sale securities	--	--	--	--	--	--	(813)	(813)
	--	--	--	52,848	--	--	(813)	52,035
Dividends on preferred stock	--	--	--	(78)	--	--	--	(78)
Dividends on common stock	--	--	--	(23,527)	--	--	--	(23,527)
Issuance of common stock	26	26	544	--	--	--	--	570
Issuance of common stock for acquisition	1,537	1,537	32,240	--	--	--	--	33,777
Treasury stock acquired, net	--	--	--	--	(13)	(1,037)	--	(1,037)
BALANCE AT DECEMBER 31, 2000	23,302	$23,302	$73,442	$191,482	(381)	$(9,067)	$(813)	$278,346

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

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BUSINESS DESCRIPTION

Black Hills Corporation and its subsidiaries operate in three primary operating groups: non-regulated independent energy, regulated electric utility and communications. The Company operates its independent energy businesses through its direct and indirect subsidiaries: Wyodak Resources related to coal, Black Hills Exploration and Production related to oil and natural gas, Enserco Energy, Black Hills Energy Resources and Black Hills Coal Network related to fuel marketing of natural gas, oil and coal, respectively, and Black Hills Energy Capital and its subsidiaries and Black Hills Generation related to independent power activities, all consolidated for reporting purposes as Black Hills Energy Ventures; operates its public utility electric operations through its subsidiary, Black Hills Power, Inc.; and operates its communication operations through its indirect subsidiaries Black Hills Fiber Systems, Black Hills FiberCom and Daksoft. For further descriptions of the Company's business segments see Note 13.

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

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned subsidiaries. Generally, the Company uses equity accounting for investments of which it owns between 20 and 50 percent and investments in partnerships under 20 percent if the Company exercises significant influence.

All significant intercompany balances and transactions have been eliminated in consolidation except for revenues and expenses associated with intercompany coal sales in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." Total intercompany coal sales not eliminated were $9.7 million, $7.7 million and $10.3 million in 2000, 1999 and 1998, respectively.

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

As noted in Note 14, Black Hills Energy Capital made several acquisitions during 2000. The Company's consolidated statements of income include operating activity of these companies beginning with their acquisition date.

The Company uses the proportionate consolidation method to account for its working interests in oil and gas properties.

MINORITY INTEREST IN SUBSIDIARIES

Minority interest in results of operations of consolidated subsidiaries represents the minority shareholders' share of the income or loss of various consolidated subsidiaries. The minority interest in the consolidated balance sheets reflect the amount of the underlying net assets of various consolidated subsidiaries attributable to the minority shareholders.

REGULATORY ACCOUNTING

Black Hills Power is subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's non-regulated businesses.

Black Hills Power follows the provisions of SFAS No. 71, and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating Black Hills Power. As a result of Black Hills Power's 1995 rate case settlement, a 50-year depreciable life for Neil Simpson II is used for financial reporting purposes. If Black Hills Power were not following SFAS 71, a 35 to 40 year life would 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 Black Hills Power's generation operations. In the event Black Hills Power determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company would be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict Black Hills Power's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure the continuing application of SFAS 71 is appropriate.

CASH EQUIVALENTS

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

AVAILABLE FOR SALE SECURITIES

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

INVENTORY

Materials, supplies and fuel are stated at the lower of cost or market on a first-in, first-out basis.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PROPERTY, PLANT AND EQUIPMENT

The components of property, plant and equipment are as follows, at December 31:

	2000	1999
	(IN THOUSANDS)	
Independent energy	$ 430,979	$125,371
Electric utility	530,529	523,461
Communications	110,486	50,621
Other	135	591
	$1,072,129	$700,044

Additions to property, plant and equipment are recorded at cost when placed in service. Included in the cost of regulated construction projects is an allowance for funds used during construction (AFUDC) which represents the approximate composite cost of borrowed funds and a return on capital used to finance the project. The AFUDC was computed at an annual composite rate of 9.7, 8.3 and 10.1 percent during 2000, 1999 and 1998, respectively. In addition, the Company capitalizes interest, when applicable, on certain non-regulated construction projects. The amount of AFUDC and interest capitalized was $2.0 million, $1.2 million and $0.2 million in 2000, 1999 and 1998, respectively. The cost of regulated electric property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, together with removal cost less salvage, is charged to accumulated depreciation. Retirement or disposal of all other assets, except for oil and gas properties as described below, result in gains or losses recognized as a component of income. Repairs and maintenance of property are charged to operations as incurred.

Depreciation provisions for regulated electric property, plant and equipment is computed on a straight-line basis using an annual composite rate of 2.8 percent in 2000, 3.1 percent in 1999 and 3.0 percent in 1998. Non-regulated property, plant and equipment is depreciated on a straight-line basis using estimated useful lives ranging from 3 to 39 years. Depletion of coal, oil and gas properties is computed using the cost method.

The Company periodically evaluates assets under SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to Be Disposed Of," which requires that such assets be probable of future recovery at each balance sheet date. As of December 31, 2000 and 1999, no significant write-downs were required.

GOODWILL AND INTANGIBLE ASSETS

Goodwill represents the excess of acquisition costs over the fair market value of the net assets of acquired businesses and is being amortized on a straight-line basis over the estimated useful lives of such assets, which range from 8 to 25 years. The cost of other acquired intangibles is amortized on a straight-line basis over their estimated useful lives. Amortization expense was $3.1 million, $2.7 million and $0.7 million in 2000, 1999 and 1998, respectively. Accumulated amortization was $6.7 million, $3.6 million and $0.9 million at December 31, 2000, 1999 and 1998, respectively.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

INCOME TAXES

The Company uses the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax bases of assets and liabilities. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. To the extent such income taxes are recoverable or payable through future rates, regulatory assets and liabilities have been recorded in the accompanying consolidated balance sheets.

Deferred taxes are provided on all significant temporary differences, principally depreciation and depletion. Investment tax credits have been deferred in the electric operation and the accumulated balance is amortized as a reduction of income tax expense over the useful lives of the related electric property which gave rise to the credits.

REVENUE RECOGNITION

Generally, revenue is recognized at the time products and services are delivered. Fuel marketing businesses also use the mark-to-market method of accounting. Under that method all energy trading activities are recorded at fair value as of the balance sheet date and net gains or losses resulting from the revaluation of these contracts to fair value are recognized currently in the results of operations. In the fourth quarter of 2000, the Company adopted Securities and Exchange Commission Staff Accounting Bulletin No. 101, "Revenue Recognition" (SAB 101), which provides guidance on the recognition, presentation and disclosure of revenue in financial statements. The adoption of SAB 101 did not have a material impact on the financial statements.

OIL AND GAS OPERATIONS

The Company accounts for its oil and gas activities under the full cost method. Under the full cost method, all productive and nonproductive costs related to acquisition, exploration and development drilling activities are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Under the full cost method, net capitalized costs may not exceed the present value of proved reserves.

EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share is computed by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed under the treasury stock method and is calculated to compute the dilutive effect of outstanding stock options and conversion of preferred shares.

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

USE OF ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Ultimate results could differ from those estimates.

RECLASSIFICATIONS

Certain 1999 and 1998 amounts in the financial statements have been reclassified to conform to the 2000 presentation. These reclassifications had no effect on the Company's common stockholders' investment or results of operations, as previously reported.

ACCOUNTING PRONOUNCEMENTS

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." SFAS 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

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

SFAS 133 requires that on date of initial adoption, an entity shall recognize all freestanding derivative instruments in the balance sheet as either assets or liabilities and measure them at fair value. The difference between a derivative's previous carrying amount and its fair value shall be reported as a transition adjustment. The transition adjustment resulting from adopting this Statement shall be reported in net income or other comprehensive income, as appropriate, as the effect of a change in accounting principle in accordance with paragraph 20 of Accounting Principles Board (APB) Opinion No. 20, "Accounting Changes."

Upon adoption of SFAS 133, most of the Company's energy trading activities previously accounted for under Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10) will fall under the purview of SFAS 133. The effect from this adoption on the energy trading companies and energy trading activities will not be material because, unless otherwise noted, the trading companies will not designate their energy trading activities as hedge

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

instruments. This "no hedge" designation will result in these derivatives being measured at fair value and gains and losses recognized currently in earnings. This treatment under SFAS 133 will be comparable to the accounting under EITF 98-10.

At December 31, 2000, the Company had certain non-trading energy contracts documented as cash flow hedges. These contracts are defined as derivatives under SFAS 133 and meet the requirements for cash flow hedges. Because these non-trading energy contracts were documented as hedges prior to adoption, the transition adjustment will be reported in accumulated other comprehensive income. The aggregated entry for the derivatives identified as energy cash flow hedges will increase derivative assets by $1.4 million, increase the derivative liabilities by $4.0 million and decrease accumulated other comprehensive income by $2.6 million.

At December 31, 2000, the Company had interest rate swaps documented as cash flow hedges. These contracts are defined as derivatives under SFAS 133 and meet the requirements for cash flow hedges. Because these contracts were documented as hedges prior to adoption, the transition adjustment will be reported in accumulated other comprehensive income. The interest rate swap transactions have a notional amount of $127.4 million and the associated transition adjustments will increase derivative liabilities by $7.5 million and decrease accumulated other comprehensive income by $7.5 million.

(2) PRICE RISK MANAGEMENT

The Company is exposed to market risk stemming from changes in commodity prices. These changes could cause fluctuations in the Company's earnings and cash flows. In the normal course of business, the Company actively manages its exposure to these market risks by entering into various hedging transactions, which are authorized under its policies that place clear controls on these activities. Hedging transactions involve the use of a variety of derivative financial instruments.

Effective January 1, 1999, the Company adopted the provisions of EITF 98-10, pursuant to the implementation requirements stated therein. The resulting effect of adoption of the provisions of EITF 98-10 was to alter the Company's comprehensive method of accounting for energy-related contracts, as defined in that Statement.

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

The Company, through its independent energy business group, utilizes financial instruments for its 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.

These derivatives are not held for speculative purposes but rather serve to hedge the Company's 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

(2) PRICE RISK MANAGEMENT (CONTINUED)

unrealized gains and losses are recorded as a component of income. Because the Company does not, as a policy, permit speculation with "open" positions, substantially all of its 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 (MMBTUS)	MAX. TERM (YEARS)
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

	VOLUME COVERED (TONS)	MAX. TERM (YEARS)
Coal tons sold	988,000	1
Coal tons purchased	896,000	1

DECEMBER 31, 1999	VOLUME COVERED (MMBTUS)	MAX. TERM (YEARS)
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 sheet 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

(2) PRICE RISK MANAGEMENT (CONTINUED)

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, the Company enters into swaps and costless collar transactions. The transactions are used to hedge price risk from sales of the Company's forecasted crude oil and natural gas production. For such transactions, the Company utilizes hedge accounting.

At December 31, 2000, the Company had fixed-for-float swaps for 17,000 barrels per month for the year 2001 to hedge its crude oil price risk with a fair value that approximates cost. The Company had fixed-for-float swaps for 10,000 barrels per month for the year 2002 to hedge its crude oil price risk with a fair value of $0.4 million. The Company also had costless collars (purchased puts--sold calls) for 10,000 barrels per month for 2001 with a fair value of $0.3 million. The Company hedged its forecasted 2001 natural gas production with fixed-for-float swaps. The Company had fixed-for-float swaps for 1,581,000 MMBtus with a fair value of $(3.4) million. These amounts are not reflected in the Company's December 31, 2000 consolidated balance sheet, but will be recorded as part of the adoption of SFAS 133 on January 1, 2001.

FINANCING ACTIVITIES

To reduce risk from fluctuations in interest rates, the Company enters into interest rate swap transactions. These transactions are used to hedge interest rate risk for variable rate debt financing. For such transactions, the Company utilizes hedge accounting. At December 31, 2000, the Company had interest rate swaps with notional amount of $127.4 million, having a maximum term of six years and a fair value of $(7.5) million.

At December 31, 2000, the Company 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 debt to a fixed rate.

CREDIT RISK

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

(3) INVESTMENTS IN ASSOCIATED COMPANIES

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

- A 33.33 percent interest in Millennium Pipeline Company, L.P., a Texas limited partnership which owns and operates an oil pipeline in the Gulf Coast region of Texas. The Company has a

(3) INVESTMENTS IN ASSOCIATED COMPANIES (CONTINUED)

carrying amount in the investment of $6.9 million and $4.8 million as of December 31, 2000 and 1999, respectively. The partnership had assets of $22.0 million and $15.7 million, liabilities of $1.0 million and $1.6 million, and net income (loss) of $2.8 million and $(0.2) million as of, and for the years ended December 31, 2000 and 1999, respectively.

- As part of the Indeck Capital acquisition, the Company acquired a 5 percent, 6 percent and 5 percent interest in Energy Investors Fund, L.P., Energy Investors Fund II, L.P., and Project Finance Fund III, L.P., respectively, which in turn have investments in numerous electric generating facilities in the United States and elsewhere. The Company has a carrying amount in the investment of $8.4 million at December 31, 2000. As of, and for the year ended December 31, 2000, the funds had assets of $186.8 million, liabilities of $16.0 million and net income of $27.1 million.

- As part of the Indeck Capital acquisition, the Company acquired a 50 percent interest in two natural gas-fired cogeneration facilities located in Rupert and Glenns Ferry, Idaho. At December 31, 2000 the Company's carrying amount in the investment is $4.1 million which includes $0.5 million that represents the cost of the investment over the value of the underlying net assets of the projects. This excess is being amortized over 19 years. As of, and for the year ended December 31, 2000, these projects had assets of $26.0 million, liabilities of $18.7 million and net income of $0.9 million.

- As part of the Indeck Capital acquisition, the Company directly and indirectly acquired approximately 32 percent of Harbor Cogeneration Company, which in turn owns an 80 megawatt cogeneration facility located near the City of Long Beach in Los Angeles County, California. At December 31, 2000 the Company's carrying amount in the investment is $42.2 million, which includes $13.7 million that represents the cost of the investment over the value of the underlying net assets of Harbor. This excess is being amortized over 15 years. As of, and for the year ended December 31, 2000, Harbor had assets of $41.7 million, liabilities of $0.8 million and net income of $28.8 million.

(4) COMMON STOCK

STOCK OPTION AND EMPLOYEE STOCK PURCHASE PLANS

The Company has a stock option plan (Stock Option Plan), which allows for the granting of stock options with exercise prices equal to the stock's market value on the date of grant, and an employee stock purchase plan (ESPP Plan). The Company accounts for such plans under APB Opinion No. 25, and has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock Based Compensation" (SFAS No. 123). Accordingly, no compensation cost has been recognized.

The Company may grant options for up to 1,000,000 shares of common stock under the Stock Option Plan. The Company has granted options on 934,450 shares through December 31, 2000. The option exercise price equals the fair market value of the stock on the day of the grant. The options granted vest one-third a year for three years and all expire after ten years from the grant date.

(4) COMMON STOCK (CONTINUED)

A summary of the status of the stock option plans at December 31, 2000, 1999 and 1998, and changes during the years then ended are as follows:

	2000		1999		1998	
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Balance at beginning of year	431,450	$21.35	292,700	$20.29	182,700	$18.69
Granted	492,500	25.22	140,250	23.58	113,000	22.79
Forfeited	(4,000)	23.25	(1,500)	23.06	--	--
Exercised	(5,033)	21.33	--	--	(3,000)	16.67
Balance at end of year	914,917	23.43	431,450	21.35	292,700	20.29
Exercisable at end of year	292,891	20.43	182,400	19.19	84,800	18.06

Exercise prices on options outstanding at December 31, 2000, range from $16.67 to $37.69 with a weighted average remaining contractual life of approximately 8.5 years.

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

	2000	1999	1998
Fair value of options at grant date	$3.88	$4.16	$0.69
Weighted average risk-free interest rate	6.30%	6.68%	4.70%
Weighted average expected price volatility	20.60%	19.85%	16.74%
Weighted average expected dividend yield	4.20%	4.50%	4.20%
Expected life in years	10	10	10

Had compensation cost been determined consistent with SFAS No. 123, the Company's net income and earnings per share would have been reduced to the following pro forma amounts for the years ended December 31:

	2000	1999	1998
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Net income available for common:			
As reported	$52,770	$37,067	$25,808
Pro forma	$52,432	$36,877	$25,717
Earnings per share (basic and diluted):			
As reported--			
--Basic	$ 2.39	$ 1.73	$ 1.19
--Diluted	$ 2.37	$ 1.73	$ 1.19
Pro forma--			
--Basic	$ 2.38	$ 1.72	$ 1.19
--Diluted	$ 2.35	$ 1.72	$ 1.19

(4) COMMON STOCK (CONTINUED)

The Company issued 21,394, 19,565 and 12,824 shares of common stock under the ESPP Plan in 2000, 1999 and 1998, respectively. At December 31, 2000, 226,176 shares are reserved and available for issuance under the ESPP Plan. The Company sells the shares to employees at 90 percent of the stock's market price on the offering date. The fair value per share of shares sold in 2000 was $21.66.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

The Company has a Dividend Reinvestment and Stock Purchase Plan under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100 percent of the recent average market price. The Company has the option of issuing new shares or purchasing the shares on the open market. The Company purchased shares on the open market in 2000, 1999 and 1998. At December 31, 2000, 1,290,797 shares of unissued common stock were available for future offerings under the Plan.

(5) PREFERRED STOCK

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

During 2000, the Company issued 4,000 preferred shares in the Indeck Capital acquisition. The preferred shares issued are non-voting, cumulative, no-par shares with a dividend rate equal to 1 percent per annum per share, computed on the basis of $1,000 per share plus an amount equal to any dividend declared payable with respect to the common stock, multiplied by the number of shares of common stock into which each share of preferred stock is convertible. The record and payment dates are the same as the record and payment dates with respect to the payment of dividends on common stock. No dividend may be declared or paid with respect to common stock unless such a dividend is declared and paid with respect to the preferred stock. The preferred stock is senior to the common stock in liquidation events.

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

(6) LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	2000	1999
	(IN THOUSANDS)	
First mortgage bonds:		
6.50% due 2002	$ 15,000	$ 15,000
9.00% due 2003	3,215	4,255
8.06% due 2010	30,000	30,000
9.49% due 2018	5,130	5,420
9.35% due 2021	35,000	35,000
8.30% due 2024	45,000	45,000
	133,345	134,675
Other long-term debt:		
Pollution control revenue bonds at 6.7% due 2010	12,300	12,300
Pollution control revenue bonds at 7.5% due 2024	12,200	12,200
Other	3,911	2,855
	28,411	27,355
Project financing debt:		
Floating-rate term loans at a weighted average rate of 8.05% at December 31, 2000 due 2009 through 2010 (a)	159,296	--
Total long-term debt	321,052	162,030
Less current maturities	(13,960)	(1,330)
Net long-term debt	$307,092	$160,700

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(a) Approximately 80 percent of the December 31, 2000 balance has been hedged with an interest rate swap moving the floating rates to fixed rates with a weighted average interest rate of 7.69 percent (see Note 2-Price Risk Management).

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

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

Certain debt instruments of the Company and its subsidiaries contain restrictive covenants, all of which the Company and its subsidiaries are in compliance with at December 31, 2000.

Scheduled maturities for the next five years are: $14.0 million in 2001, $30.0 million in 2002, $16.0 million in 2003, $16.4 million in 2004 and $17.6 million in 2005.

(7) NOTES PAYABLE

The Company had committed lines of credit with various banks of $290.0 million at December 31, 2000 and $115.0 million at December 31, 1999, which were available to support bank borrowings or to provide for letters of credit. There were $211.0 million of borrowings and $20.6 million of letters of credit issued under these lines of credit at December 31, 2000, and there were $96.6 million of borrowings and no letters of credit issued at December 31, 1999. The Company has 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 to the above lines of credit, Enserco Energy, Inc. has a $90.0 million uncommitted, discretionary line of credit to provide support for the purchases of natural gas. The Company and its subsidiaries provide no guarantee to the lender. 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.

In addition to the above lines of credit, Black Hills Energy Resources, Inc. has a $25.0 million uncommitted, discretionary credit facility. The transactional line of credit provides credit support for the purchases of crude oil of Black Hills Energy Resources. The Company and its subsidiaries provide no guarantee to the lender. At December 31, 2000 and 1999, Black Hills Energy Resources, Inc. had letters of credit outstanding of $8.5 million and $13.2 million, respectively and no balance outstanding on the overdraft line.

Our credit facilities contain restrictive covenants and include commitment fees ranging from 0.125 percent to 0.375 percent; our credit facilities with ABN AMRO Bank, NV also include utilization fees of 0.75 percent on the amount by which facility loans exceed 50 percent of the total facility commitment. The Company and its subsidiaries had complied with all the covenants at December 31, 2000.

Interest rates under the facility borrowings vary and are based, at the option of the Company at the time of the loan origination, on either (i) a prime based borrowing rate varying from prime rate (9.5 percent at December 31, 2000) to prime rate plus 1.5 percent, or (ii) on the London Interbank Offered Rate (LIBOR) (6.5 percent for a one-month LIBOR at December 31, 2000) based borrowings rates varying from LIBOR plus 0.625 percent to LIBOR plus 1.375 percent.

(8) FAIR VALUE OF FINANCIAL INSTRUMENTS

Cash of the Company is invested in money market investments such as municipal put bonds, money market preferreds, commercial paper, Eurodollars and certificates of deposit.

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

CASH AND CASH EQUIVALENTS

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

(8) FAIR VALUE OF FINANCIAL INSTRUMENTS (CONTINUED)

AVAILABLE FOR SALE SECURITIES

The fair value of the Company's investments equals the quoted market price when available and a quoted market price for similar securities if a quoted market price is not available. The Company has classified all of its marketable securities as available-for-sale as of December 31, 2000 and 1999. An unrealized loss on the Company's investments of $0.8 million was recorded as of December 31, 2000. At December 31, 1999 fair value approximated cost.

LONG-TERM DEBT

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

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

	2000 (IN THOUSANDS)	
	CARRYING AMOUNT	FAIR VALUE
Cash and cash equivalents	$ 24,913	$ 24,913
Securities available for sale	2,113	2,113
Long-term debt	321,052	337,446

	1999 (IN THOUSANDS)	
	CARRYING AMOUNT	FAIR VALUE
Cash and cash equivalents	$ 16,482	$ 16,482
Securities available for sale	7,586	7,586
Long-term debt	162,030	165,958

(9) WYODAK PLANT

The Company owns a 20 percent interest and Pacific Power owns an 80 percent interest in the Wyodak plant (the Plant), a 330 megawatt coal-fired electric generating station located in Campbell County, Wyoming. Pacific Power is the operator of the Plant. The Company receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2000, the Company's investment in the Plant included $71.8 million in electric plant and $22.4 million in accumulated depreciation. The Company's share of direct expenses of the Plant was $5.6 million, $4.9 million and $5.8 million for the years ended December 31, 2000, 1999 and 1998, respectively, and is included in the corresponding categories of operating expenses in the accompanying consolidated statements of income. Wyodak Resources supplies coal to the Plant under an agreement expiring in 2013 with a Pacific Power option to renew the agreement for an additional 10 years. This coal supply agreement is collateralized by a mortgage on and a security interest in some of Wyodak Resources' coal reserves. At December 31, 2000, approximately 17,966,000 tons of coal were covered under this agreement. Wyodak Resources' sales to

(9) WYODAK PLANT (CONTINUED)
the Plant were $23.2 million, $24.9 million and $23.2 million, for the years ended December 31, 2000, 1999 and 1998, respectively.

(10) COMMITMENTS AND CONTINGENCIES

PACIFIC POWER'S POWER SALES AGREEMENT

In 1983 the Company entered into a 40 year power agreement with Pacific Power providing for the purchase by the Company of 75 megawatts of electric capacity and energy from Pacific Power's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of Pacific Power's coal-fired electric generating plants. Costs incurred under this agreement were $14.6 million, $17.8 million and $17.5 million in 2000, 1999 and 1998, respectively.

RECLAMATION

Under its mining permit, Wyodak Resources is required to reclaim all land where it has mined coal reserves. The cost of reclaiming the land is accrued as the coal is mined. While the reclamation process takes place on a continual basis, much of the reclamation occurs over an extended period after the area is mined. Approximately $0.7 million is charged to operations as reclamation expense annually. As of December 31, 2000, accrued reclamation costs were approximately $17.7 million.

LEGAL PROCEEDINGS

On August 14, 2000, Wyodak Resources Development Corp. (Wyodak) initiated an action against PacifiCorp as it concerns the Further Restated and Amended Coal Supply Agreement, dated as of May 5, 1987 (Coal Supply Agreement). The action has been filed in the United States District Court for the District of Wyoming as Case No. 00CV155-B. Wyodak alleges that PacifiCorp has failed and refused to make complete payment to Wyodak for coal sold under the Coal Supply Agreement, and there was at that time approximately $5.0 million outstanding and allegedly due Wyodak from PacifiCorp. Wyodak alleged that PacifiCorp's actions constitute a breach of contract and asked for the appropriate monetary relief.

On August 31, 2000, PacifiCorp answered the Wyodak Complaint and additionally brought a counterclaim against Wyodak and Black Hills Corporation. In its action, PacifiCorp alleged that as a result of Wyodak's actions as it concerns its billings under the Coal Supply Agreement, PacifiCorp was entitled to cancel and terminate the Coal Supply Agreement and Coal Handling Agreement, as well as the recovery of damages. PacifiCorp alleged that Wyodak had not properly adjusted upward and downward the components which make up the coal price under the Coal Supply Agreement, and as a result PacifiCorp had been overbilled appproximately $35.0 million to $40.0 million and that Wyodak continued to overcharge PacifiCorp under the Coal Supply Agreement and the Coal Handling Agreement. PacifiCorp further alleged that the overcharges would result in additional overcharges of approximately $150.0 million through the balance of the term of the Coal Supply Agreement, which expires in June of 2013. In its action, PacifiCorp sought not only to cancel and terminate the contract but also to discharge and excuse any further obligation under the same, as well as recovery of damages as set forth above.

(10) COMMITMENTS AND CONTINGENCIES (CONTINUED)

Management is of the opinion that Wyodak has properly billed PacifiCorp under the terms of the Coal Supply Agreement and Coal Handling Agreement and PacifiCorp's withholding of payment constitutes a breach of contract on their part. Although it is impossible to predict whether or not Black Hills Corporation and Wyodak will ultimately be successful in defending the claim or, if not, what the impact might be, management believes that the disposition of this matter will not have a material adverse effect on the Company's consolidated results of operations.

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

(11) EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PENSION AND OTHER POSTRETIREMENT PLANS

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

Net pension income for the Plan was as follows:

	2000	1999	1998
	(IN THOUSANDS)		
Service cost	$ 967	$ 1,174	$ 895
Interest cost	2,885	2,598	2,406
Estimated return on assets	(5,257)	(4,162)	(4,146)
Amortization of transition amount	(90)	(90)	(90)
Amortization of prior service cost	231	89	89
Recognized net actuarial gain	(537)	--	(272)
Net pension income	$(1,801)	$ (391)	$(1,118)
Actuarial assumptions:			
Discount rate	7.5%	6.75%	7.5%
Expected long-term rate of return on assets	10.5%	10.5%	10.5%
Rate of increase in compensation levels	5.0%	5.0%	5.0%

(11) EMPLOYEE BENEFIT PLANS (CONTINUED)

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

	2000	1999
	(IN THOUSANDS)	
Beginning projected benefit obligation	$39,615	$39,490
Service cost	967	1,174
Interest cost	2,885	2,598
Actuarial losses	(48)	(3,590)
Benefits paid	(2,105)	(1,903)
Plan amendments	--	1,846
Net increase	1,699	125
Ending projected benefit obligation	$41,314	$39,615

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

	2000	1999
	(IN THOUSANDS)	
Beginning market value of plan assets	$51,212	$40,638
Benefits paid	(2,105)	(1,903)
Investment income	7,453	12,477
Ending market value of plan assets	$56,560	$51,212

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

	2000	1999
	(IN THOUSANDS)	
Fair value of plan assets	$ 56,560	$ 51,212
Projected benefit obligation	(41,314)	(39,615)
Funded status	15,246	11,597
Unrecognized:		
Net gain	(13,812)	(12,105)
Prior service cost	2,054	2,285
Transition asset	--	(90)
Prepaid pension cost	$ 3,488	$ 1,687
Accumulated benefit obligation	$ 33,374	$ 31,914

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The plans are nonqualified defined benefit plans. Expenses recognized under the plans were $0.5 million, $0.4 million and $0.4 million in 2000, 1999 and 1998, respectively.

(11) EMPLOYEE BENEFIT PLANS (CONTINUED)

Employees who are participants in the Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits coverage. These benefits are subject to premiums, deductibles, copayment provisions and other limitations. The Company may amend or change the plan periodically. The Company is not pre-funding its retiree medical plan.

The net periodic postretirement cost was as follows:

	2000	1999	1998
	(IN THOUSANDS)		
Service cost	$ 282	$225	$135
Interest cost	523	362	290
Amortization of transition obligation	150	150	150
(Gain)/loss	68	1	(42)
	$1,023	$738	$533

Funding information as of October 1 was as follows:

	2000	1999
	(IN THOUSANDS)	
Accumulated postretirement benefit obligation:		
Retirees	$ 2,478	$ 2,608
Fully eligible active participants	1,203	1,195
Other active participants	3,172	3,278
Unfunded accumulated postretirement benefit obligation	6,853	7,081
Unrecognized net loss	(1,001)	(1,667)
Unrecognized transition obligation	(1,797)	(1,947)
Accrued postretirement cost	$ 4,055	$ 3,467

For measurement purposes, an 8.5 percent annual rate of increase in healthcare benefits was assumed for 2000; the rate was assumed to decrease gradually to 6 percent in 2005 and remain at that level thereafter. The healthcare cost trend rate assumption has a significant effect on the amounts reported. A one percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 21.8 percent and the net periodic postretirement cost $0.2 million or 24.1 percent. A one percent decrease would reduce the service and interest cost by $0.1 million or 16.9 percent and decrease the net periodic postretirement cost $0.2 million or 18.6 percent. The weighted-average discount rate used in determining the accumulated postretirement benefit obligation was 7.5 percent.

DEFINED CONTRIBUTION PLAN

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. Effective January 1, 2000 (May 1, 2000 for employees covered by the collective bargaining agreement), the Company provides a

(11) EMPLOYEE BENEFIT PLANS (CONTINUED)

matching contribution of 100 percent of the employee's tax deferred contribution up to a maximum 3 percent of the employee's eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions totaled $0.6 million for 2000.

(12) INCOME TAXES

Income tax expense for the years indicated was:

	2000	1999	1998
	(IN THOUSANDS)		
Current	$28,421	$13,498	$14,243
Deferred	2,576	2,931	(1,886)
Tax credits, net	(639)	(640)	(649)
	$30,358	$15,789	$11,708

The temporary differences which gave rise to the net deferred tax liability at December 31, 2000 and 1999 were as follows:

DECEMBER 31, 2000	ASSETS	LIABILITIES	NET DEFERRED INCOME TAX ASSET (LIABILITY)
	(IN THOUSANDS)		
Accelerated depreciation and other plant-related differences	$ 5,393	$63,559	$(58,166)
Regulatory asset	1,621	--	1,621
Regulatory liability	--	1,447	(1,447)
Unamortized investment tax credits	886	--	886
Mining development and oil exploration	3,605	8,450	(4,845)
Employee benefits	3,308	1,347	1,961
Other	3,711	6,400	(2,689)
	$18,524	$81,203	$(62,679)

(12) INCOME TAXES (CONTINUED)

DECEMBER 31, 1999	ASSETS	LIABILITIES	NET DEFERRED INCOME TAX ASSET (LIABILITY)
		(IN THOUSANDS)	
Accelerated depreciation and other plant-related differences	$ --	$48,223	$(48,223)
Regulatory asset	1,792	--	1,792
Regulatory liability	--	1,380	(1,380)
Unamortized investment tax credits	1,058	--	1,058
Mining development and oil exploration	3,605	6,893	(3,288)
Employee benefits	2,833	695	2,138
Other	2,184	1,949	235
	$11,472	$59,140	$(47,668)

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

	2000	1999	1998
Federal statutory rate	35.0%	35.0%	35.0%
State income tax	1.4	--	--
Amortization of investment tax credits	(1.0)	(0.9)	(1.3)
Tax-exempt interest income	--	(0.5)	(1.1)
Percentage depletion in excess of cost	(1.1)	(1.6)	(1.7)
Other	2.2	(2.1)	0.3
	36.5%	29.9%	31.2%

(13) BUSINESS SEGMENTS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of December 31, 2000, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six business segments that include: Electric, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; Independent Energy consisting of: Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and operates oil and gas interests located in the Rocky Mountain region, Texas, California and other states; Fuel Marketing, which markets natural gas, oil, coal and related services to customers in the East Coast, Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions markets; Independent Power, which produces and sells power to wholesale customers; and Communications and Others, which primarily markets communications and software development services.

Segment information follows the same accounting policies as described in Note 1--BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES. Segment

(13) BUSINESS SEGMENTS (CONTINUED)
information included in the accompanying Consolidated Balance Sheets and Consolidated Statements of Income is as follows (in thousands):

		INDEPENDENT ENERGY						
	ELECTRIC	MINING	OIL AND GAS	FUEL MARKETING	INDEPENDENT POWER	COMMUNICATIONS & OTHERS	ELIMINATIONS	TOTAL
ASSETS								
AT DECEMBER 31, 2000								
Current assets	$133,542	$167,820	$ 3,452	$ 330,352	$ 25,645	$ 13,215	$(255,016)	$ 419,010
Total assets	627,930	251,136	36,396	346,333	375,811	132,724	(450,010)	1,320,320
AT DECEMBER 31, 1999								
Current assets	$ 93,837	$ 57,427	$ 1,988	$ 84,867	$ 52,471	$ 9,698	$(113,931)	$ 186,357
Total assets	522,285	136,372	29,381	99,064	52,690	72,711	(244,011)	668,492
AT DECEMBER 31, 1998								
Current assets	$ 43,760	$ 25,872	$ 1,335	$ 77,402	$ 4	$ 6,067	$ (13,960)	$ 140,480
Total assets	451,404	93,480	26,666	86,300	57	18,441	(116,931)	559,417

		INDEPENDENT ENERGY						
	ELECTRIC	MINING	OIL AND GAS	FUEL MARKETING	INDEPENDENT POWER	COMMUNICATIONS & OTHERS	ELIMINATIONS	TOTAL
YEAR ENDED DECEMBER 31, 2000								
Electric revenues	$173,308	$ --	$ --	$ --	$ --	$ --	$ --	$ 173,308
Coal revenues	--	30,530	--	37,099	--	--	--	67,629
Gas revenues	--	--	9,335	871,296	--	--	(14,320)	866,311
Oil revenues	--	--	7,211	458,575	--	--	--	465,786
Other operating revenues	--	--	3,782	--	39,660	11,371	(4,011)	50,802
Total operating revenues	$173,308	$ 30,530	$ 20,328	$1,366,970	$ 39,660	$ 11,371	$ (18,331)	$1,623,836
Depreciation, depletion & amortization	$ 14,966	$ 3,525	$ 4,071	$ 644	$ 3,646	$ 6,012	$ --	$ 32,864
Operating income (loss)	68,208	8,794	7,906	23,774	20,374	(14,306)	--	114,750
Interest expense	17,411	8,006	372	535	11,911	6,350	(14,243)	
Income taxes (benefit)	19,469	2,660	2,609	9,323	3,154	(6,857)	--	
Net income (loss) available for common	37,100	7,173	4,992	14,009	3,241	(12,557)	(1,188)	
Property additions, investments and acquisition of net assets	25,257	2,419	9,259	(3)	81,335*	58,922	--	

Interest expense.............	30,342
Income taxes (benefit).......	30,358
Net income (loss) available for common.................	52,770
Property additions, investments and acquisition of net assets..............	177,189

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* Excludes the non-cash acquisition of Indeck Capital, Inc. as described in Note 14.

(13) BUSINESS SEGMENTS (CONTINUED)

		INDEPENDENT ENERGY					
	ELECTRIC	MINING	OIL AND GAS	FUEL MARKETING	INDEPENDENT POWER	COMMUNICATIONS & OTHERS	ELIMINATIONS
YEAR ENDED DECEMBER 31, 1999							
Electric revenues............	$133,222	$ --	$ --	$ --	$ --	$ --	$ --
Coal revenues................	--	31,095	--	39,212	--	--	--
Gas revenues.................	--	--	5,399	382,809	--	--	--
Oil revenues.................	--	--	4,676	192,207	--	--	--
Other operating revenues.....	--	--	2,977	--	--	3,423	(3,145)
Total operating revenues.....	$133,222	$ 31,095	$ 13,052	$ 614,228	$ --	$ 3,423	$ (3,145)
Depreciation, depletion & amortization...............	$ 15,552	$ 3,259	$ 2,953	$ 2,757	$ --	$ 546	$ --
Operating income (loss)......	52,286	12,606	3,978	(2,248)	(157)	(4,574)	--
Interest expense.............	13,830	1,260	568	719	111	1,172	(2,200)
Income taxes (benefit).......	12,446	3,439	968	50	(58)	(1,056)	--
Net income (loss) available for common.................	27,362	9,715	2,462	(185)	(109)	(1,263)	(915)
Property additions, investments and acquisition of net assets.............	31,911	5,422	9,968	5,947	52,319	49,042	--

	TOTAL
YEAR ENDED DECEMBER 31, 1999	
Electric revenues............	$ 133,222
Coal revenues................	70,307
Gas revenues.................	388,208
Oil revenues.................	196,883
Other operating revenues.....	3,255
Total operating revenues.....	$ 791,875
Depreciation, depletion & amortization...............	$ 25,067
Operating income (loss)......	61,891
Interest expense.............	15,460
Income taxes (benefit).......	15,789
Net income (loss) available for common.................	37,067
Property additions, investments and acquisition of net assets.............	154,609

		INDEPENDENT ENERGY					
	ELECTRIC	MINING	OIL AND GAS	FUEL MARKETING	INDEPENDENT POWER	COMMUNICATIONS & OTHERS	ELIMINATIONS
YEAR ENDED DECEMBER 31, 1998							
Electric revenues............	$129,236	$ --	$ --	$ --	$ --	$ --	$ --
Coal revenues................	--	31,413	--	12,924	--	--	--
Gas revenues.................	--	--	4,073	375,136	--	--	--
Oil revenues.................	--	--	5,131	117,185	--	--	--
Other operating revenues.....	--	--	3,358	798	--	2,437	(2,437)
Total operating revenues.....	$129,236	$ 31,413	$ 12,562	$ 506,043	$ --	$ 2,437	$ (2,437)
Depreciation, depletion & amortization...............	$ 14,881	$ 3,252	$ 18,760**	$ 690	$ --	$ --	$ --
Operating income (loss)......	49,896	12,723	(12,340)**	41	--	(1,087)	--
Interest income..............	13,572	10	355	731	--	39	--
Income taxes (benefit).......	12,612	4,126	(4,689)**	(116)	(64)	(161)	--
Net income (loss) available for common.................	24,825	9,750	(7,976)**	(346)	(118)	(226)	(101)
Property additions, investments and acquisition of net assets.............	11,451	1,406	10,169	2,384	--	1,815	--

	TOTAL

YEAR ENDED DECEMBER 31, 1998	
Electric revenues	$ 129,236
Coal revenues	44,337
Gas revenues	379,209
Oil revenues	122,316
Other operating revenues	4,156
Total operating revenues	$ 679,254
Depreciation, depletion & amortization	$ 37,583
Operating income (loss)	49,233
Interest income	14,707
Income taxes (benefit)	11,708
Net income (loss) available for common	25,808
Property additions, investments and acquisition of net assets	27,225

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** Includes the impact of a $13.5 million pretax write-down of certain oil and natural gas properties.

(14) ACQUISITIONS

On July 7, 2000, the Company acquired Indeck Capital, Inc., and merged it into Black Hills Energy Capital, Inc. The new entity owns varying interests in 14 operating independent power plants in California, New York, Massachusetts, Colorado and Idaho totaling approximately 350 megawatts.

The acquisition was a stock transaction with the Company issuing 1,536,747 shares of common stock to the shareholders of Indeck priced at $21.98 per share (approximately 7 percent of the Company's common stock after the transaction), along with $4 million in preferred stock, resulting in a

(14) ACQUISITIONS (CONTINUED)

purchase price of approximately $37.8 million. Additional consideration, consisting of common and preferred stock, may be paid in the form of an earn-out over a four-year period. The earn-out consideration will be based on the acquired company's earnings during such period and cannot exceed $35.0 million in total. Additional consideration paid out under the earn-out will be recorded as an increase to goodwill.

The acquisition has been accounted for under the purchase method of accounting and, accordingly, the purchase price has been allocated to the acquired assets and liabilities based on estimates of the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. Fair values in the allocation include assets acquired of approximately $151.1 million (excluding goodwill) and liabilities assumed of approximately $138.7 million. As of December 31, 2000, the purchase price and related acquisition costs exceeded the fair values assigned to net tangible assets by approximately $25.4 million, which was recorded as goodwill and is being amortized over 25 years on a straight-line basis.

Prior to the closing of the Indeck Capital transaction, there was no material relationship between its shareholders and the Company or any of its affiliates, any director or officer of the Company or any of their associates, except that the Company through its subsidiaries and Indeck jointly owned Black Hills Colorado, LLC and both parties held interests in Indeck North American Power Partners, L.P. and Indeck North American Power Fund, L.P. Black Hills Colorado owns 111 megawatts of combustion turbine generating facilities in the Front Range of Colorado.

In addition, the Company made several step-acquisitions resulting in consolidation of $169.5 million of assets and $138.8 million of liabilities. The related transactions are as follows:

- Through various transactions, acquired an additional 27.11 percent interest in Indeck North American Power Fund, L.P. and an additional 46.66 percent interest in Indeck North American Power Partners, L.P., for approximately $13.0 million in cash.

- Acquired a 39.6 percent interest in each of Northern Electric Power Company, L.P. and South Glens Falls Limited Partnership for approximately $4.2 million in cash.

- Acquired substantially all of the partnership interests in Middle Falls Limited Partnership, Sissonville Limited Partnership and New York State Dam Limited Partnership for approximately $12.9 million in cash.

Operating activities of the above acquired companies have been included in the accompanying consolidated financial statements since their respective acquisition dates. The following unaudited pro forma condensed results of operations presents the effect of the acquisitions as if they had occurred on January 1, 1999. The pro forma financial data is provided for informational purposes only and does not purport to be indicative of the results that would have been obtained if the acquisitions had been effected on January 1, 1999. The pro forma financial information reflects the amortization of the excess

(14) ACQUISITIONS (CONTINUED)

purchase price over the fair value of net assets acquired and the income tax effect thereof for the years ended December 31, 2000 and 1999 as follows:

	2000	1999
	(UNAUDITED, IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	
Revenues	$1,668,851	$840,891
Operating income	$ 139,053	$ 73,900
Net income available for common	$ 57,542	$ 34,310
Net income per share:		
Basic	$ 2.47	$ 1.49
Diluted	$ 2.45	$ 1.49

(15) OIL AND GAS RESERVES (UNAUDITED)

Black Hills Exploration and Production has interests in 639 producing oil and gas properties in seven states. Black Hills Exploration and Production also holds leases on approximately 185,926 net undeveloped acres.

The following table summarizes Black Hills Exploration and Production's quantities of proved developed and undeveloped oil and natural gas reserves, estimated using constant year-end product prices, as of December 31, 2000, 1999 and 1998, and a reconciliation of the changes between these dates. These estimates are based on reserve reports by Ralph E. Davis Associates, Inc., an independent engineering company selected by the Company. Such reserve estimates are based upon a number of variable factors and assumptions which may cause these estimates to differ from actual results.

	2000		1999		1998	
	OIL	GAS	OIL	GAS	OIL	GAS
	(IN THOUSANDS OF BARRELS OF OIL AND MMCF OF GAS)					
Proved developed and undeveloped reserves						
Balance at beginning of year	4,109	19,460	2,368	15,952	2,495	9,052
Production	(352)	(3,285)	(309)	(2,801)	(353)	(2,068)
Additions	625	4,228	376	7,718	1,149	10,721
Property sales	--	--	(164)	(66)	--	--
Revisions to previous estimates	31	(1,999)	1,838	(1,343)	(923)	(1,753)
Balance at end of year	4,413	18,404	4,109	19,460	2,368	15,952
Proved developed reserves at end of year included above	3,047	16,418	2,819	14,391	1,463	10,041
Year-end prices	$26.80	$ 9.78	$24.28	$ 1.99	$ 9.16	$ 1.93

In December 1998, Black Hills Exploration and Production recognized a $13.5 million pretax loss related to a write-down of oil and gas properties. The write-down was primarily due to historically low crude oil prices, lower natural gas prices and decline in value of certain unevaluated properties.

(16) QUARTERLY HISTORICAL DATA (UNAUDITED)

The Company operates on a calendar year basis. The following table sets forth selected unaudited historical operating results and market data for each quarter of 2000 and 1999.

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)			
2000:				
Operating revenues	$247,959	$336,978	$453,231	$585,668
Operating income	16,872	15,200	42,519	40,159
Net income available for common stock	9,061	8,061	16,285	19,363
Earnings per common share:				
Basic	0.42	0.38	0.71	0.84
Diluted	0.42	0.38	0.71	0.83
Dividends paid per share	0.27	0.27	0.27	0.27
Common stock prices:				
High	25.19	25.19	30.13	46.06
Low	20.44	20.88	22.00	27.00
1999:				
Operating revenues	$168,201	$186,195	$219,779	$217,700
Operating income	15,980	13,786	16,675	15,450
Net income available for common stock	9,035	7,763	9,725	10,544
Earnings per common share:				
Basic	0.42	0.36	0.45	0.50
Diluted	0.42	0.36	0.45	0.50
Dividends paid per share	0.26	0.26	0.26	0.26
Common stock prices:				
High	26.50	23.88	25.63	23.31
Low	21.00	21.00	22.19	20.31

(17) SUBSEQUENT EVENT (UNAUDITED)

On March 8, 2001, Black Hills Energy Capital, Inc., the Company's independent power subsidiary, announced it had signed a definitive agreement to purchase a 240 megawatt gas-fired turbine generation facility (Fountain Valley) 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 existing Company facilities in Colorado and Wyoming. All necessary permitting has been approved and the plant is expected to phase in its generation capacity beginning in May 2001. The Company also announced that it has signed an 11-year contract with Public Service of Colorado to utilize the plant for peaking purposes. The contract is a tolling arrangement in which the Company assumes no fuel costs. The cost of the project is expected to be approximately $175 million. The Company expects to finance the project primarily with non-recourse debt and negotiations are presently under way with certain lenders.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors of
Indeck Capital, Inc. and Subsidiaries

In our opinion, based upon our audit and the report of other auditors, the accompanying consolidated balance sheet and the related consolidated statements of operations, changes in stockholders' equity and cash flows present fairly, in all material respects, the financial position of Indeck Capital, Inc. and Subsidiaries (the "Company") at December 31, 1999, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States. These consolidated financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these consolidated financial statements based on our audit. We did not audit the financial statements of EIF Investors, Inc., a wholly-owned subsidiary, which statements reflect total assets of approximately $5,884,000 at December 31, 1999, and total revenues of approximately $2,900,000 for the year ended December 31, 1999. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for EIF Investors, Inc., is based solely on the report of other auditors. We conducted our audit of the consolidated financial statements in accordance with auditing standards generally accepted in the United States which require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall consolidated financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Milwaukee, Wisconsin

June 9, 2000, except for information in Note 11, for which the date is
August 30, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Members of
EIF Management Holdings, LLC:

We have audited the accompanying consolidated balance sheet of EIF Management Holdings, LLC (a Delaware limited liability company) and its subsidiaries as of December 31, 1999 and the related consolidated statements of operations and members' equity and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of EIF Management Holdings, LLC and its subsidiaries as of December 31, 1999 and the consolidated results of their operations and their cash flows for the year then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

February 11, 2000 (except for Note 5, as to which the date is February 28, 2000)

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
EIF Group Management Company:

We have audited the accompanying balance sheets of EIF Group Management Company (a Massachusetts general partnership) as of December 31, 1999 and 1998 and the related statements of operations, partners' capital and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of EIF Group Management Company as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

February 11, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Project Finance Partners, L.P.:

We have audited the accompanying balance sheets of Project Finance Partners, L.P. (a Delaware limited partnership) as of December 31, 1999 and 1998 and the related statements of operations, partners' capital (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Project Finance Partners, L.P. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Project Finance Fund III, L.P.:

We have audited the accompanying balance sheets of Project Finance Fund III, L.P. (a Delaware limited partnership) as of December 31, 1999 and 1998 and the related statements of operations, partners' capital and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Project Finance Fund III, L.P. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Energy Investors Management Company:

We have audited the accompanying balance sheets of Energy Investors Management Company (a Massachusetts general partnership) as of December 31, 1999 and 1998 and the related statements of operations, partners' capital and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Investors Management Company as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

February 11, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Energy Investors Partners II, L.P.:

We have audited the accompanying balance sheets of Energy Investors Partners II, L.P. (a Delaware limited partnership) as of December 31, 1999 and 1998 and the related statements of operations, comprehensive income, partners' capital (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Investors Partners II, L.P. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Energy Investors Fund II, L.P.:

We have audited the accompanying balance sheets of Energy Investors Fund II, L.P. (a Delaware limited partnership) as of December 31, 1999 and 1998 and the related statements of operations, comprehensive income, partners' capital and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Investors Fund II, L.P. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders of
Energy Investors Management, Inc.:

We have audited the accompanying balance sheets of Energy Investors Management, Inc. (a Delaware corporation) as of December 31, 1999 and 1998 and the related statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Investors Management, Inc. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

February 11, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Energy Investors Partners, L.P.:

We have audited the accompanying balance sheets of Energy Investors Partners, L.P. (a Delaware limited partnership) as of December 31, 1999 and 1998 and the related statements of operations, comprehensive income, partners' deficit and cash flows for the year then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Energy Investors Partners, L.P. as of December 31, 1999 and 1998 and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of
Energy Investors Fund, L.P.:

We have audited the accompanying consolidated balance sheets of Energy Investors Fund, L.P. (a Delaware limited partnership) and its subsidiary as of December 31, 1999 and 1998 and the related consolidated statements of operations, comprehensive income, partners' capital and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Energy Investors Fund, L.P. and its subsidiary as of December 31, 1999 and 1998 and the consolidated results of their operations and their cash flows for the years then ended in conformity with generally accepted accounting principles.

Arthur Andersen LLP
Boston, Massachusetts

April 21, 2000

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

DECEMBER 31, 1999

ASSETS	
Current assets:	
Cash and cash equivalents	$ 1,552,886
Accounts receivable	1,222,144
Accounts receivable, related parties	188,928
Notes receivable, related parties	1,407,815
Inventory	233,379
Prepaid expenses and other	290,350
Total current assets	4,895,502
Property and equipment, net	6,614,617
Construction in progress	52,690,392
Equity investments	38,821,406
Goodwill	423,678
Other	29,016
Total assets	$103,474,611
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current liabilities:	
Accounts payable	$ 1,536,370
Accounts payable, related parties	10,250
Deferred management fee income	717,750
Interest payable (including interest payable to related parties of $813,423)	994,911
Income taxes payable	134,580
Notes payable	22,439
Other	51,943
Total current liabilities	3,468,243
Contracts payable	4,770,966
Power sales receipts in excess of avoided costs	6,133,856
Notes payable	88,001,408
Deferred income tax liability	110,800
Minority interest in subsidiaries	134,531
Total liabilities	102,619,804
Stockholders' equity:	
Common stock, no par value, 200,000 shares authorized, 200,000 issued	40,080
Retained earnings	814,727
Total stockholders' equity	854,807
Total liabilities and stockholders' equity	$103,474,611

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

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 1999

Revenues and income from equity investments:	
Management fees	$ 2,434,112
Project fees	1,761,459
Consulting fees	529,879
Income from equity investments	3,600,448
Reimbursable costs and other	2,134,413
	10,460,311
Administrative and general expenses	10,140,500
Income from operations	319,811
Other income (expense):	
Interest expense, related parties of $2,107,153	(4,522,988)
Interest income, related parties	746,821
Financing fees	(60,000)
Other income, net	631,438
Loss before income taxes	(2,884,918)
Income tax benefit	(867,556)
Net loss	$(2,017,362)

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

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 1999

	COMMON STOCK			
	SHARES	AMOUNT	RETAINED EARNINGS	TOTAL
Balances, December 31, 1998	160,000	$ 80	$ 1,817,953	$ 1,818,033
Net loss	--	--	(2,017,362)	(2,017,362)
Issuance of common stock in conjunction with the acquisition of North American Funding, L.L.C. (Note 3)	40,000	40,000	1,014,136	1,054,136
Balances, December 31, 1999	200,000	$40,080	$ 814,727	$ 854,807

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

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 1999

Cash flows from operating activities:	
Net loss	$ (2,017,362)
Adjustments to reconcile net loss to net cash used in operating activities:	
Depreciation and amortization	415,455
Loss on sale of property and equipment	6,313
Write-off of note receivable	227,505
Deferred income taxes	(1,086,600)
Income from equity investments	(3,600,448)
Distributions from equity investments	3,600,448
Changes in assets and liabilities, net of effects of business acquisitions:	
Accounts receivable	(250,026)
Income taxes	217,302
Accounts payable and accrued liabilities	729,812
Power sales receipts in excess of avoided costs	642,679
Other	164,935
Net cash used in operating activities	(949,987)
Cash flows from investing activities:	
Business acquisitions, net of cash acquired	245,894
Capital expenditures	(52,771,891)
Investments	(672,593)
Notes receivable	(140,279)
Payments on notes receivable	945,018
Distributions from equity investments in excess of earnings	2,847,711
Other	116,722
Net cash used in investing activities	(49,429,418)
Cash flows from financing activities:	
Payments under revolving credit agreement, net	(1,800,000)
Proceeds from notes payable	52,319,000
Payments on long-term debt	(28,616)
Net cash provided by financing activities	50,490,384
Net change in cash and cash equivalents	110,979
Cash and cash equivalents at beginning of year	1,441,907
Cash and cash equivalents at end of year	$ 1,552,886
Cash paid during the year for interest	$ 4,943,000
Cash paid during the year for income taxes	$ 142,000

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION OF INDECK CAPITAL, INC.:

Indeck Capital, Inc. (the "Company") was incorporated in 1994 to participate in the rapidly changing power generation industry. The Company is engaged in the acquisition, development, ownership and operation of power generation facilities through direct investment and investment in various projects and funds. The Company has primarily focused on the North American market.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements include the accounts of Indeck Capital, Inc. and its majority-owned subsidiaries. All significant intercompany accounts and transactions are eliminated in consolidation. Investments in partially-owned affiliates are accounted for by the equity method when the Company's interest exceeds 20%.

ESTIMATES: Preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

CASH EQUIVALENTS: The Company considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents.

PROPERTY AND EQUIPMENT: Property and equipment are stated at cost. Depreciation is provided using the straight line method over the lives of the related assets, ranging from 3-30 years.

INVESTMENTS: As they represent interests in limited partnerships, the Company's investments are recorded under the equity method. The Company's investments are increased by its share of earnings and reduced by distributions received from or losses incurred by the investment.

GOODWILL: Goodwill is amortized on the straight-line method over 37 years. The Company continually assesses the carrying value of goodwill for potential impairment using an undiscounted cash flow approach.

POWER SALES RECEIPTS IN EXCESS OF AVOIDED COSTS: The Company's wholly-owned subsidiary, Adirondack Hydro Development Corporation ("AHDC"), entered into a 40-year power purchase agreement ("PPA") with Niagara Mohawk Power Company ("NMPC") between 1985 and 1992, committing the parties to sell and buy, respectively, the output of the Otter Creek facility. The Warrensburg Hydro Power facility, which is owned through subsidiaries of AHDC, also has a 40-year PPA with NMPC. The contracts establish a base rate per kilowatt hour of energy and an annual fixed escalator for the first 15-year period. The cumulative difference between the base payment and "avoided cost" (the greater of $0.06 per kwh or NMPC's actual cost of production avoided by reason of its agreement with AHDC for the Otter Creek facility, and NMPC's actual cost of production avoided by reason of its agreement for the Warrensburg Hydro Power facility), including interest at 125 percent of the 360-day Treasury bill rate, is tracked by NMPC and will be used to adjust the contractual rate over the second 15 years of the respective agreements. In addition, if the projected cumulative difference exceeds the cost of the facilities at any time during years 6 through 15, the fixed escalation is suspended and the respective rates may be reduced. Revenue is recognized when the power is transmitted in accordance with the terms of the PPA and is included in project fees in the consolidated statement of operations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (CONTINUED)

At December 31, 1999, the cumulative excess of the base payment over the avoided cost (power sales receipts in excess of avoided costs), plus interest, was $6,133,856.

INCOME TAXES: Deferred income taxes are provided on a liability method whereby deferred income tax assets are recognized for deductible temporary differences and operating loss and tax credit carryforwards, and deferred income tax liabilities are recognized for taxable temporary differences. Temporary differences are the differences between the reported amounts of assets and liabilities and their tax basis. Deferred income tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred income tax assets will not be realized. Deferred income tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

3. ACQUISITIONS:

INDECK COLORADO, L.L.C.: On November 23, 1999, the Company entered into an agreement with the Public Service Company of Colorado ("PSCC") to purchase PSCC's ownership interests in two power plants, the Arapahoe plant and the Valmont plant, and to operate these plants for PSCC. To execute this transaction, the Company formed Indeck Colorado, L.L.C. ("Indeck Colorado") with Black Hills Corporation ("Black Hills"). The Company and Black Hills are each 50% members in Indeck Colorado, although the Company is the managing member of the venture and has the exclusive authority to manage the operations and affairs of Indeck Colorado. Indeck Colorado obtained an $82,000,000 financing arrangement from Black Hills and borrowed $52,319,000 under this arrangement on December 22, 1999 to purchase the plant ownership interests from PSCC (Note 7). The acquisition was accounted for using the purchase method of accounting, with the entire purchase price allocated to the plant assets purchased, which consisted of construction in progress at December 31, 1999.

NORTH AMERICAN FUNDING, L.L.C.: On December 10, 1999, the Company issued 40,000 shares of common stock to the members of North American Funding, L.L.C. ("NAF"), a related entity, in exchange for each member's ownership interest in NAF. The assets and liabilities of NAF were transferred to the Company at historical cost as NAF and the Company are under common ownership control. NAF's total assets and liabilities were approximately $7,100,000 and $6,200,000, respectively, at December 10, 1999, including $246,000 of cash acquired.

The following unaudited information presents, on a pro forma basis, the results of operations as if the acquisitions had occurred at the beginning of 1999:

Revenues and income from equity investments.................	$11,600,000
Net loss..	(1,500,000)

4. NOTES RECEIVABLE:

The Company has demand notes receivable with certain members of executive management and affiliated entities for approximately $1,408,000 at December 31, 1999. Notes receivable of approximately $1,408,000 at December 31, 1999, bear interest at prime rate plus 1% (9.50% at December 31, 1999). A $200,000 note receivable (including accrued interest of approximately $28,000) was written off during 1999.

4. NOTES RECEIVABLE: (CONTINUED)

A $5,908,000 note receivable from a related party outstanding at December 31, 1998 was eliminated as part of the acquisition of NAF by the Company (Note 3).

5. INVESTMENTS:

INDECK NORTH AMERICAN POWER FUND, L.P.: The Company has a 17.1% limited partnership interest in Indeck North American Power Fund, L.P. at December 31, 1999. The investment balance as of December 31, 1999 was approximately $8,028,000.

INDECK NORTH AMERICAN POWER PARTNERS, L.P.: The Company has a 13.3% limited partnership interest in Indeck North American Power Partners, L.P. The investment balance as of December 31, 1999 was approximately $62,000.

EIF FUNDS: The Company's wholly-owned subsidiary, EIF Investors, Inc., has general and limited partnership interests in various entities as follows:

INVESTMENT	OWNERSHIP %	BALANCE OF INVESTMENT 12/31/99
Energy Investors Fund, L.P.	5	$ 1,861,062
Energy Investors Partners, L.P.	50	(1,530,467)
Energy Investors Mgmt. Inc	50	121,427
Energy Investors Fund II, L.P.	6	1,694,850
Energy Investors Partners II, L.P.	38	(98,608)
Energy Investors Mgmt. Company	50	242,716
Project Finance Fund III, L.P.	5	2,930,714
Project Finance Partners	50	105,552
EIF Group Management Company	50	303,693
EIF Management Holdings, LLC	50	253,255
Goodwill	--	1,732,384
Total		$ 7,616,578

During 1999, EIF Investors, Inc. purchased a 50% interest in EIF Management Holdings, LLC, a limited liability company that was organized on March 17, 1998 and commenced operations on January 1, 1999.

NORTHERN ELECTRIC POWER CO., L.P.: The Company's wholly-owned subsidiary, AHDC, has general and limited partnership interests of 1.0% and 19.8%, respectively, in Northern Electric Power Co., L.P. The investment balance as of December 31, 1999 was approximately $11,626,000.

SOUTH GLENS FALLS LIMITED PARTNERSHIP: The Company's wholly-owned subsidiary, AHDC, has general and limited partnership interests of 1.0% and 19.8%, respectively, in South Glens Falls Limited Partnership. The investment balance as of December 31, 1999 was approximately $3,661,000.

5. INVESTMENTS: (CONTINUED)

INDECK IDAHO PARTNERSHIPS: The Company's wholly-owned subsidiary, Indeck Idaho, has general and limited partnership interests in two entities as follows:

INVESTMENT	OWNERSHIP %	BALANCE OF INVESTMENT 12/31/99
Rupert Cogeneration Partners, Ltd	50	$1,807,849
Glenns Ferry Cogeneration Partners, Ltd	50	1,512,934
Operating and Maintenance Agreements	--	1,791,013
Goodwill	--	1,694,414
Total		$6,806,210

CARIBBEAN BASIN POWER FUND, LTD.: During 1999, the Company purchased a 3.3% interest in Caribbean Basin Power Fund, Ltd. The investment balance at December 31, 1999 was approximately $555,000.

INDECK HARBOR, L.L.C.: As part of the acquisition of NAF (Note 3), the Company acquired a 1% limited partnership interest in Indeck Harbor, L.L.C. The investment balance at December 31, 1999 was approximately $406,000.

INDECK PEPPERELL POWER ASSOCIATES, INC.: As part of the acquisition of NAF (Note 3), the Company acquired a 1% ownership interest in Indeck Pepperell Power Associates, Inc. The investment balance at December 31, 1999 was approximately $56,000.

Summarized financial information of the Company's significant investments is as follows:

	INDECK NORTH AMERICAN POWER FUND, L.P.	ENERGY INVESTORS PARTNERS, L.P.	ENERGY INVESTORS FUND, L.P.	ENERGY INVESTORS FUND II, L.P.	PROJECT FINANCE FUND III, L.P.
1999					
Assets	$48,577,035	$ 37,075	$60,408,170	$58,225,746	$59,588,473
Liabilities	1,536,388	3,074,150	19,007,824	253,116	316,242
Minority interest	461,982	--	--	--	--
Equity	46,578,665	(3,037,075)	41,400,346	57,972,630	59,272,231
Total revenues	16,742,881	3,634,537	27,282,383	9,730,477	5,701,157
Net income (loss)	2,155,503	2,205,035	22,508,907	6,328,379	(428,339)
Equity investment	8,028,235	(1,530,467)	1,861,062	1,694,850	2,930,714
Company's share of net income (loss)	219,778	1,096,898	925,470	472,152	70,368
Company's percentage ownership	17%	50%	5%	6%	5%

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5. INVESTMENTS: (CONTINUED)
CONTINUED

1999	NORTHERN ELECTRIC POWER CO., L.P.	SOUTH GLENS FALLS LIMITED PARTNERSHIP	RUPERT COGENERATION PARTNERS, LTD.	GLENNS FERRY COGENERATION PARTNERS, LTD.
Assets	$94,565,394	$35,993,255	$13,868,875	$13,954,925
Liabilities	78,796,269	28,577,111	10,216,655	10,898,491
Minority interest	--	--	--	--
Equity	15,769,125	7,416,144	3,652,220	3,056,434
Total revenues	14,630,540	5,401,474	5,561,875	5,479,366
Net income (loss)	1,708,777	879,698	615,626	524,946
Equity investment	11,626,387	3,660,725	1,807,849	1,512,934
Company's share of net income (loss)	355,426	182,977	304,735	259,848
Company's percentage ownership	21%	21%	50%	50%

6. PROPERTY AND EQUIPMENT:

Property and equipment at December 31, 1999 consists of:

Land	$ 308,015
Power generation facilities	7,080,959
Leasehold improvements	322,333
Furniture and fixtures	264,202
Equipment	1,293,377
Vehicles	46,902
	9,315,788
Accumulated depreciation	2,701,171
	$6,614,617

7. NOTES PAYABLE:

Notes payable at December 31, 1999 consists of:

Note payable to Black Hills Corporation, due June 30, 2000 with interest at LIBOR plus 2% (8.00% at December 31, 1999), collateralized by property and equipment of Indeck Colorado L.L.C. (Note 3). This note was refinanced subsequent to December 31, 1999 (Note 11)	$52,319,000
Note payable with a bank under a $25 million revolving credit agreement dated June 30, 1998 with interest at the corporate base rate (9.00% at December 31, 1999), collateralized by pledge agreements and guarantees by current stockholders of the Company; includes covenants that require, among other things, the Company to maintain positive levels of tangible net worth. The bank has extended the due date for repayment of the note to June 30, 2000. The Company's contract payable is guaranteed by the available credit under the revolving credit agreement, therefore the amount available under revolving credit agreement at December 31, 1999 is further reduced by the contract payable amount of $4,770,966 at December 31, 1999. This note was refinanced subsequent to December 31, 1999 (Note 11)	18,433,693
Note payable to Indeck Energy Services, Inc. (a related entity), due on demand with interest at 11.22%, guaranteed by current stockholder of the Company. Indeck Energy Services, Inc. did not intend to demand payment before December 31, 1999. This note was refinanced subsequent to December 31, 1999 (Note 11)	17,002,902
Note payable to a bank, due August 8, 2001 with interest at the prime rate plus .50% (9.00% at December 31, 1999), collateralized by property and equipment. This note was paid in full in June 2000	268,252
	88,023,847
Less current portion	22,439
Notes payable, non-current	$88,001,408

8. RELATED PARTY TRANSACTIONS:

Management fees, project fees, consulting fees and reimbursable costs are earned by the Company as services are performed under management agreements for related entities that are not consolidated in the Company's consolidated financial statements.

9. INCOME TAXES:

The provision for income taxes is comprised of the following:

Current provision:	
Federal	$ --
State	219,044
	219,044
Deferred benefit:	
Federal	(855,100)
State	(231,500)
	(1,086,600)
	$ (867,556)

The components of the deferred income tax assets and liabilities as of December 31, 1999 were as follows:

Deferred income tax assets:	
Management fees/other	$ 286,700
Investments	515,600
Net operating loss carryforwards--federal	2,124,000
Net operating loss carryforwards--state	633,000
Power sales receipts in excess of avoided costs	200,600
Alternative minimum tax credits	359,100
Note receivable	90,900
Deferred income tax liabilities:	
Investments	(4,311,900)
Property and equipment	(8,800)
Deferred income taxes, net	$ (110,800)

The following is a reconciliation of the statutory income tax rate to the effective tax rates reflected in the statement of income:

Statutory federal income tax rate	34.0%
Increase (reduction) in tax rate resulting from:	
Non-deductible goodwill amortization	(3.2)
State taxes	0.3
Other	(1.0)
	30.1%

At December 31, 1999, federal net operating loss carryforwards of approximately $6,247,000 expiring in 2013-2020, were available for the reduction of future taxable income. If certain substantial changes in the Company's ownership should occur, there may be an annual limitation on the amount of carryforwards which can be utilized.

10. COMMITMENTS:

The Company may be required to make additional portfolio investments, pursuant to capital call provisions of certain investment agreements, of up to $7,900,000 at December 31, 1999. These commitments expire at various times through 2001.

11. SUBSEQUENT EVENTS:

In January 2000, the Company and its stockholders entered into a definitive agreement to sell all of the outstanding stock of the Company to Black Hills Corporation ("Black Hills). The sale of the Company was completed July 7, 2000.

In conjunction with the sale of the Company to Black Hills, a new debt arrangement (the "Arrangement") with various financial institutions was negotiated by the Company on June 30, 2000. Under the terms of the Arrangement, the Company may borrow up to $115,000,000 under a credit revolver. The Arrangement expires July 6, 2003 with interest at various rates based on the conditions of the Arrangement and includes covenants, the most restrictive of which require the Company to maintain certain debt ratios and levels of net worth. Proceeds from this Arrangement were used to pay the $18,433,693 note payable to a bank and the $17,002,902 note payable to Indeck Energy (Note 7).

An additional debt arrangement (the "Credit Facility") with a bank was negotiated by the Company on August 30, 2000. Under the terms of the Credit Facility, the Company may borrow up to $60,000,000 under a term loan arrangement. The Credit Facility expires May 31, 2007, but may be extended to May 31, 2010 provided certain conditions are met. The Credit Facility bears interest at various rates based on the conditions of the Credit Facility and includes covenants, the most restrictive of which require the Company to maintain certain debt ratios and levels of net worth. Proceeds from this Credit Facility were used to pay the $52,319,000 note payable to Black Hills Corporation (Note 7).

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

JUNE 30, 2000 (UNAUDITED)

ASSETS	
Current assets:	
Cash and cash equivalents	$ 3,339,140
Accounts receivable	3,094,299
Inventory	680,985
Prepaid expenses and other	337,256
Total current assets	7,451,680
Property and equipment, net of accumulated depreciation of $1,439,346	85,781,912
Equity in investments	40,578,710
Goodwill	417,551
Deferred tax assets	286,700
Other	88,105
Total assets	$134,604,658
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current liabilities:	
Notes payable	$113,030,183
Accounts payable	1,079,570
Deferred management fee income	332,006
Accrued liabilities	4,917,723
Total current liabilities	119,359,482
Long term liabilities:	
Contracts payable	4,770,966
Power sales receipts in excess of avoided costs	6,524,224
Capital lease obligation	12,389
Deferred income tax liability	1,229,287
Minority interest	602,921
Total long term liabilities	13,139,787
Total liabilities	132,499,269
Stockholders' equity:	
Common stock	40,080
Retained earnings	2,065,309
Total stockholders' equity	2,105,389
Total liabilities and equity	$134,604,658

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Revenues:		
Operating revenue	$ 4,314,065	$ 371,459
Management fees	1,027,450	1,216,759
Project fees	670,807	613,356
Consulting fees revenue	71,840	236,266
Income from equity investments	4,643,163	2,526,534
Reimbursable costs and other	1,266,835	991,807
Total revenues	11,994,160	5,956,181
Administrative and general expenses	6,945,328	3,353,111
Income from operations	5,048,832	2,603,070
Other income:		
Interest expense	(2,923,917)	(2,237,422)
Interest income	72,446	433,749
Financing fees	(95,000)	(50,000)
Other income	28,750	5,153
Income before income taxes	2,131,111	754,550
Income tax provision	(880,540)	(304,333)
Net income	$ 1,250,571	$ 450,217

INDECK CAPITAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Cash flows from operating activities:		
Net income	$ 1,250,571	$ 450,217
Adjustments to reconcile net income to net cash used in operating activities:		
Equity income from investments	(4,543,163)	(2,526,534)
Cash distributions from investments	2,785,859	2,124,731
Depreciation and amortization	535,166	204,510
Deferred income taxes	1,119,702	(70,118)
Increase in accounts receivable and other current assets	(769,923)	(258,098)
Increase in accounts payable and other current liabilities	2,882,295	(115,290)
Other	531,480	366,872
	3,791,987	176,290
Cash flows from investing activities:		
Property and investment additions	(27,012,069)	(21,078)
Cash flows from financing activities:		
Increase in short-term borrowings	25,006,336	485,837
Increase in cash and cash equivalents	1,786,254	641,049
Cash and cash equivalents:		
Beginning of six month period	1,552,886	1,441,907
End of six month period	$ 3,339,140	$ 2,082,956

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of
Indeck North American Power Fund, L.P.

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, partners' equity and cash flows present fairly, in all material respects, the financial position of Indeck North American Power Fund, L.P. (the "Partnership") at December 31, 1999, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Milwaukee, Wisconsin

February 25, 2000

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED BALANCE SHEET

DECEMBER 31, 1999

ASSETS	
Cash and cash equivalents	$ 509,208
Accounts receivable	1,266,166
Prepaid management fee	717,750
Investment in Harbor Cogeneration Company	40,335,958
Plant and equipment, less accumulated depreciation of $1,335,000	5,625,140
Other assets	122,813
Total assets	$48,577,035
LIABILITIES AND PARTNERS' EQUITY	
Accounts payable	$ 1,536,388
Minority interest	461,982
Partners' equity	46,578,665
Total liabilities and partners' equity	$48,577,035

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

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENT OF INCOME

FOR THE YEAR ENDED DECEMBER 31, 1999

Revenues and income from equity investments:	
Equity income from investment	$ 5,646,341
Operating revenues	10,672,645
Other	423,895
	16,742,881
Expenses:	
Operating expenses	11,819,558
Selling, general and administrative expenses	2,722,838
Total expenses	14,542,396
Income before minority interest	2,200,485
Minority interest	44,982
Net income	$ 2,155,503

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

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 1999

	INDECK NORTH AMERICAN POWER PARTNERS, L.P.	INDECK CAPITAL, INC.	NORTH AMERICAN FUNDING, L.L.C.	CHASE MANHATTAN INVESTMENT HOLDINGS, INC.	DYNEGY MARKETING AND TRADE CAPITAL CORP.	MIAMI VALLEY LEASING, INC.
Balances at December 31, 1998	$ 530,888	$3,665,003	$ 5,606,679	$3,701,395	$3,665,003	$3,722,912
Capital contributions	5,750	41,708	63,889	42,150	41,708	41,708
Capital distributions	(121,117)	(672,041)	(1,027,934)	(678,665)	(672,041)	(672,041)
Net income	43,088	219,778	131,153	140,110	138,804	138,804
Partner ownership transaction	--	4,773,787	(4,773,787)	--	--	--
Balances at December 31, 1999	$ 458,609	$8,028,235	$ --	$3,204,990	$3,173,474	$3,231,383

CONTINUED ON NEXT PAGE

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

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' EQUITY (CONTINUED)

FOR THE YEAR ENDED DECEMBER 31, 1999

CONTINUED

	PSEG GLOBAL, INC.	IGC ACQUISITIONS, INC.	PARIBAS NORTH AMERICAN, INC.	ABB ENERGY VENTURES, INC.	DRESDNER BANK, A.G., GRAND CAYMAN BRANCH	TOTAL
Balances at December 31, 1998	$3,230,796	$3,665,003	$11,140,574	$ 9,271,681	$ 5,606,678	$53,806,612
Capital Contributions	--	41,708	126,893	105,597	63,889	575,000
Capital Distributions	(672,041)	(672,041)	(2,042,620)	(1,699,975)	(1,027,934)	(9,958,450)
Net income	220,264	138,804	421,640	350,931	212,127	2,155,503
Partner ownership transaction	--	--	--	--	--	--
Balances at December 31, 1999	$2,779,019	$3,173,474	$ 9,646,487	$ 8,028,234	$ 4,854,760	$46,578,665

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

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 1999

Cash flows from operating activities:	
Net income	$ 2,155,503
Adjustments to reconcile net income to net cash provided by operating activities:	
Equity income from investment	(5,646,341)
Cash distributions from investment	5,646,341
Minority interest	44,982
Amortization and depreciation	736,941
Changes in assets and liabilities:	
Account receivable	(772,996)
Accounts payable	1,049,593
Other	12,721
Net cash provided by operating activities	3,226,744
Cash flows from investing activities:	
Capital expenditures for plant and equipment	(75,898)
Return of capital from investment	6,183,659
Net cash provided by investing activities	6,107,761
Cash flows from financing activities:	
Capital contributions from partners	575,000
Capital distributions to partners	(9,958,450)
Capital contributions from minority interests	5,808
Capital distributions to minority interests	(118,300)
Net cash used in financing activities	(9,495,942)
Decrease in cash and cash equivalents	(161,437)
Cash and cash equivalents, beginning of year	670,645
Cash and cash equivalents, end of year	$ 509,208

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND OPERATIONS

Indeck North American Power Fund, L.P. (the "Partnership") is a limited partnership whose operations commenced May 16, 1995. The Partnership terminates in 2005. The purpose and business of the Partnership is to invest in established utility and non-utility generating assets in the United States and Canada.

Indeck North American Power Partners, L.P. (the "General Partner") serves as the general partner and has the exclusive authority for the management, operation and policy of the Partnership. The General Partner has a 1% interest in the Partnership.

Profits and losses are generally allocated in a manner such that the capital accounts of partners, immediately after making such allocation, are proportionate to the distributions that would have been made pursuant to the agreement if the partnership were dissolved.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Indeck North American Power Fund, L.P. and its subsidiaries, Indeck Harbor, L.L.C. ("Indeck Harbor") and Indeck Pepperell Power Associates, Inc. ("Indeck Pepperell"), both of which are 99% owned. All significant intercompany transactions have been eliminated.

ESTIMATES

The preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

CASH EQUIVALENTS

The Partnership considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents.

INCOME TAXES

The profits and losses of the Partnership are subject to income taxes directly at the partner level. Accordingly, the Partnership's financial statements do not reflect a provision for income taxes at the Partnership level.

Deferred income taxes at Indeck Pepperell are provided on a liability method whereby deferred income tax assets are recognized for deductible temporary differences and operating loss and tax credit carryforwards, and deferred income tax liabilities are recognized for taxable temporary differences. Temporary differences are the differences between the reported amounts of assets and liabilities and their tax bases. Deferred income tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred income tax assets will not be realized. Deferred income tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PLANT AND EQUIPMENT

Plant and equipment are stated at cost. Depreciation is provided for using the straight-line method over the estimated lives of the related assets, ranging from 5-25 years. The majority of these assets relate to the generation facility. Depreciation expense was $556,000 for 1999.

REVENUE RECOGNITION

Operating revenue is recognized when steam is transmitted.

3. EQUITY INVESTMENT IN HARBOR COGENERATION COMPANY

Under the terms of the general partnership agreement, Indeck Harbor, L.L.C. cannot exercise effective control over the investment in Harbor Cogeneration Company (the "Venture"). Accordingly, Indeck Harbor records its investment in the Venture under the equity method, whereby the investment is increased by its share of the Venture's earnings and reduced by distributions received from the Venture.

The Venture entered into a power sales agreement (the "Agreement") with Southern California Edison ("Edison") for the sale of energy produced by the cogeneration facility operated by the Venture. The Agreement has a term of 30 years from April 12, 1989. The Venture is paid energy prices based on 20% of the stated marginal cost of energy and 80% of avoided cost for a period of 10 years, both as defined in the Agreement. For the remaining term of the Agreement, energy prices will equal 100% of avoided cost. In addition to the above energy prices, the Venture is paid capacity revenues over the term of the Agreement based on a stated amount per kilowatt hour as adjusted by a performance bonus factor.

Effective February 15, 1999, the Venture entered into a Contract Termination Agreement with Edison which terminated the Agreement. Upon termination, the Venture may continue to sell power, which it did during certain months in 1999, but operations are presently suspended while management explores available options for the Venture, which may include entering into new power sales arrangements that would terminate the Contract Termination Agreement. The Contract Termination Agreement requires Edison to pay the Venture $126.5 million, in quarterly payments ranging from $4.6 million to $2.1 million from the effective date through October 1, 2008 for early termination of the Agreement. During 1999, the Venture recorded approximately $16.4 million related to the Contract Termination Agreement, which is included in operating revenues in the Venture's Statement of Income.

3. EQUITY INVESTMENT IN HARBOR COGENERATION COMPANY (CONTINUED)

The summarized balance sheet of Harbor Cogeneration Company at December 31, 1999 is as follows:

Assets:	
Cash and cash equivalents	$ 4,202,215
Accounts receivable	16,746
Other	1,652,161
Plant and equipment, net	31,634,894
Total assets	$37,506,016
Liabilities:	
Accounts payable	$ 1,250,440
Partners' equity	36,255,576
Total liabilities and partners' equity	$37,506,016

The summarized statement of income of Harbor Cogeneration Company for the year ended December 31, 1999 is as follows:

Operating and contract termination revenues	$18,733,612
Operating expenses	11,141,525
Operating income	7,592,087
Other income	2,562,147
Interest expense	(3,991)
Net income	$10,150,243

4. OTHER INCOME

In 1999, other income is primarily comprised of a settlement payment received related to a breach of contract dispute.

5. RELATED PARTY TRANSACTIONS

In accordance with the Limited Partnership Agreement, the General Partner receives an annual management fee equal to 1.5% of the Limited Partners' aggregate capital commitments as defined. In 1999, the Partnership paid a management fee of $2,153,000, as well as reimbursement of certain expenditures of $376,000.

On December 10, 1999, Indeck Capital, Inc. ("Indeck"), a limited partner, acquired North American Funding, L.L.C. ("NAF"), also a limited partner. As a result of this transaction, Indeck assumed NAF's partnership interest in the Partnership.

6. INCOME TAXES

The components of the deferred tax assets and liabilities at Indeck Pepperell are as follows at December 31, 1999:

Deferred tax asset:	
Net operating loss carryforward	$2,274,000
Deferred tax liability:	
Plant and equipment	304,000
	1,970,000
Valuation allowance	1,970,000
Net deferred income taxes	$ --

Indeck Pepperell has net operating loss carryforwards of approximately $5,647,000 expiring in 2011-2014, available to offset future taxable income. A valuation allowance has been established for the deferred tax assets due to the uncertainty regarding their ultimate realization.

7. SUBSEQUENT EVENT

On January 28, 2000, Dynegy Marketing and Trade Capital Corp. ("DMTCC") was acquired by Black Hills Energy Capital, Inc. ("Black Hills"). As a result of this transaction, Black Hills assumed DMTCC's partnership interest in the Partnership.

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED BALANCE SHEET

JUNE 30, 2000 (UNAUDITED)

ASSETS	
Current assets:	
Cash and cash equivalents	$ 1,197,276
Accounts receivable	1,049,114
Prepaid management fee	332,006
Other	96,038
Total current assets	2,674,434
Investment in Harbor Cogeneration Company	39,207,389
Plant and equipment, net of $1,508,427 of accumulated depreciation	5,607,319
Other assets	964
Total assets	$47,490,106
LIABILITIES AND PARTNERS' EQUITY	
Current liabilities:	
Accounts payable	$ 719,017
Minority interest	462,166
Partners' equity	46,308,923
Total liabilities and partners' equity	$47,490,106

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENTS OF INCOME

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Revenues:		
Equity income from investment	$ 4,231,430	$ 1,758,781
Operating revenues	2,013,605	4,497,821
Other	88,090	414,022
Total revenues	6,333,125	6,670,624
Expenses:		
Operating expenses	2,045,404	5,006,460
Selling, general and administrative expenses	950,337	1,488,660
Total expenses	2,995,741	6,495,120
Income before minority interest	3,337,384	175,504
Minority interest	42,733	12,439
Net income	$ 3,294,651	$ 163,065

INDECK NORTH AMERICAN POWER FUND, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Cash flows from operating activities:		
Net income	$ 3,294,651	$ 163,065
Adjustments to reconcile net income to net cash provided by operating activities:		
Equity income from investments	(3,631,430)	(1,758,781)
Cash distribution from investment	3,631,430	1,758,781
Minority interest	42,733	4,989
Amortization and depreciation	173,646	365,860
Changes in assets and liabilities:		
Accounts receivable	217,052	(655,641)
Prepaid management fee	385,744	0
Accounts payable	(817,372)	435,648
Other	25,811	14,506
Net cash provided by operating activities	3,322,265	328,427
Cash flows from investing activities:		
Return of capital from investment	1,128,570	5,661,219
Capital expenditures for plant and equipment	(155,826)	(19,950)
Net cash provided by investing activities	972,744	5,641,269
Cash flows from financing activities:		
Capital contributions	650,000	575,000
Capital distributions to partners	(4,214,391)	(6,669,176)
Capital contributions from minority interest	5,050	5,750
Capital distributions to minority interest	(47,600)	(66,692)
Net cash used in financing activities	(3,606,941)	(6,155,118)
Increase (decrease) in cash	688,068	(185,422)
Cash, beginning of period	509,208	670,645
Cash, end of period	$ 1,197,276	$ 485,223

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of
Indeck North American Power Partners, L.P.

In our opinion, the accompanying balance sheet and the related statements of operations, partners' equity and cash flows present fairly, in all material respects, the financial position of Indeck North American Power Partners, L.P. (the "Partnership") at December 31, 1999, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Milwaukee, Wisconsin

February 25, 2000

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

BALANCE SHEET

DECEMBER 31, 1999

ASSETS	
Cash	$ 3,535
Accounts receivable, affiliates	38,405
Prepaid management fee	717,750
Investment in Indeck North American Power Fund, L.P.	458,609
Total assets	$1,218,299
LIABILITIES AND PARTNERS' EQUITY	
Accounts payable, affiliates	$ 39,627
Unearned management fee revenue	717,750
Total liabilities	757,377
Partners' equity	460,922
Total liabilities and partners' equity	$1,218,299

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

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 1999

Revenues and income from equity investments:	
Fees and reimbursable expenses	$2,529,062
Equity income from investment	43,088
	2,572,150
Expenses:	
Selling, general and administrative expenses	3,088,000
Net loss	$ (515,850)

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

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENT OF PARTNERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 1999

	INDECK NORTH AMERICA, INC.	INDECK CAPITAL, INC.	CHASE MANHATTAN INVESTMENT HOLDINGS, INC.	DYNEGY MARKETING AND TRADE CAPITAL CORP.	MIAMI VALLEY LEASING, INC.
Balances at December 31, 1998....	$10,824	$134,503	$ 72,661	$145,316	$146,662
Capital contributions............	57	826	442	885	885
Capital distributions............	(1,111)	(13,702)	(7,407)	(14,816)	(14,816)
Net loss.........................	(5,158)	(63,854)	(34,505)	(69,010)	(69,010)
Balances at December 31, 1999....	$ 4,612	$ 57,773	$ 31,191	$ 62,375	$ 63,721

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

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENT OF PARTNERS' EQUITY (CONTINUED)

FOR THE YEAR ENDED DECEMBER 31, 1999

CONTINUED

	PSEG GLOBAL, INC.	IGC ACQUISITIONS, INC.	PARIBAS NORTH AMERICAN INC.	ABB ENERGY VENTURES, INC.	TOTAL
Balances at December 31, 1998	$136,224	$145,316	$145,316	$145,316	$1,082,138
Capital contributions	--	885	885	885	5,750
Capital distributions	(14,816)	(14,816)	(14,816)	(14,816)	(111,116)
Net loss	(67,283)	(69,010)	(69,010)	(69,010)	(515,850)
Balances at December 31, 1999	$ 54,125	$ 62,375	$ 62,375	$ 62,375	$ 460,922

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

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 1999

Cash flows from operating activities:	
Net loss	$(515,850)
Adjustments to reconcile net loss to net cash provided by operating activities:	
Amortization	545,417
Equity income from investment	(43,088)
Cash distributions from investment	43,088
Changes in operating assets and liabilities:	
Account receivable, affiliates	(2,410)
Accounts payable, affiliates	3,882
Net cash provided by operating activities	31,039
Cash flows from investing activities:	
Contributions to Indeck North American Power Fund, L.P.	(5,750)
Return of capital from investment	78,029
Net cash provided by investing activities	72,279
Cash flows from financing activities:	
Capital contributions from partners	5,750
Capital distributions to partners	(111,116)
Net cash used in financing activities	(105,366)
Decrease in cash	(2,048)
Cash, beginning of year	5,583
Cash, end of year	$ 3,535

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

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND OPERATIONS

Indeck North American Power Partners, L.P. (the "Partnership") is a limited partnership whose operations commenced May 16, 1995. The partnership terminates in 2005. The purpose and business of the Partnership is to own a 1% interest in Indeck North American Power Fund, L.P. ("INAPF") and act as its General Partner. The Partnership received $2,153,000 in 1999 for management fees, which are recognized as management services are performed, and $376,000 for reimbursable expenditures in 1999, from INAPF and incurred expenses of the same amount to Indeck North America, Inc., the General Partner of the Partnership.

Profits and losses are generally to be allocated based on the partners' respective percentage interests, except for amortization costs which are not to be allocated to the General Partner.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ESTIMATES

Preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

INCOME TAXES

The profits and losses of the Partnership are subject to income taxes directly at the partner level. Accordingly, the Partnership's financial statements do not reflect a provision for income taxes.

INVESTMENTS

As it represents an interest in a limited partnership, the investment in INAPF is recorded under the equity method. The Partnership's investment is increased by its share of INAPF's earnings and reduced by distributions received from INAPF.

3. EQUITY INVESTMENT IN INAPF

The summarized balance sheet of INAPF at December 31, 1999 is as follows:

Assets:	
Cash and cash equivalents	$ 509,208
Accounts receivable	1,266,166
Prepaid management fee	717,750
Investment in Harbor Cogeneration Company	40,335,958
Plant and equipment, net	5,625,140
Other assets, net	122,813
Total assets	$48,577,035
Liabilities:	
Accounts payable	$ 1,536,388
Minority interest	461,982
Partners' equity	46,578,665
Total liabilities and partners' equity	$48,577,035

The summarized statement of income for INAPF for the year ended December 31, 1999 is as follows:

Revenues and income from equity investments:	
Equity income from investment	$ 5,646,341
Operating expenses	10,672,645
Other	423,895
	16,742,881
Expenses:	
Operating	11,819,558
Selling, general and administrative	2,722,838
Minority interest	44,982
Total expenses and minority interest	14,587,378
Net income	$ 2,155,503

4. COMMITMENTS

The Partnership has an unfunded capital commitment to INAPF of $878,992 at December 31, 1999. Funding is required as INAPF makes additional portfolio investments. The commitment expires in 2000.

5. SUBSEQUENT EVENT

On January 28, 2000, Dynegy Marketing and Trade Capital Corp. ("DMTCC") was acquired by Black Hills Energy Capital, Inc. ("Black Hills"). As a result of this transaction, Black Hills assumed DMTCC's partnership interest in the Partnership.

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

BALANCE SHEET

JUNE 30, 2000 (UNAUDITED)

ASSETS	
Current assets:	
Cash	$ 12
Accounts receivable, affiliates	6,834
Prepaid management fee	332,006
Total current assets	338,852
Other assets	
Investment in INAPF	464,749
Total assets	$803,601
LIABILITIES AND PARTNERS' CAPITAL	
Current liabilities:	
Accounts payable, affiliates	17,964
Accrued management fee	332,005
Total current liabilities	349,969
Partners' capital:	
Beginning capital	460,921
Contributions	6,500
Distributions	(42,144)
Net income	28,355
Total partners' capital	453,632
Total liabilities and partners' capital	$803,601

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENTS OF OPERATIONS

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Revenues	$896,154	$1,353,133
Equity in income on investment	41,784	12,397
Total revenues	937,938	1,365,530
Selling, general and administrative expenses	909,583	1,638,022
Net income (loss)	$ 28,355	$ (272,492)

INDECK NORTH AMERICAN POWER PARTNERS, L.P.

STATEMENTS OF CASH FLOWS

FOR THE SIX MONTHS ENDED JUNE 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Cash flows from operating activities:		
Net income	$ 28,355	$(272,492)
Adjustments to reconcile net income to net cash provided by operating activities:		
Equity income from investment	(41,784)	(12,397)
Cash distributions from investment	41,784	12,397
Amortization	0	272,709
Changes in assets and liabilities:		
Accounts receivable	56,369	12,619
Accounts payable	(46,463)	(5,896)
Net cash provided by operating activities	38,261	6,940
Cash flows from investing activities:		
Contribution to Indeck North American Power Fund, L.P.	(6,500)	(5,750)
Return of capital from investment	360	65,061
Net cash used in (provided by) investing activities	(6,140)	59,311
Cash flows from financing activities:		
Contributions	6,500	5,750
Distributions to partners	(42,144)	(77,458)
Net cash used in financing activities	(35,644)	(71,708)
Decrease in cash	(3,523)	(5,457)
Cash, beginning of period	3,535	5,583
Cash, end of period	$ 12	$ 126

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of Northern Electric
Power Co., L.P.

In our opinion, the accompanying balance sheet and the related statements of earnings, of partners' equity and of cash flows present fairly, in all material respects, the financial position of Northern Electric Power Co., L.P. (the "Partnership") at December 31, 1999, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Milwaukee, Wisconsin

February 25, 2000

NORTHERN ELECTRIC POWER CO., L.P.

BALANCE SHEET

DECEMBER 31, 1999

Assets:	
Cash and cash equivalents (Note 1)	$ 75,906
Accounts receivable--power sales	1,049,813
Prepaid expenses and supplies	427,325
Property and equipment:	
Hydroelectric facilities (Notes 1 and 2)	99,037,055
Less accumulated depreciation	(10,284,710)
Property and equipment, net	88,752,345
Deferred financing costs, net of accumulated amortization of $1,638,464 (Note 1)	4,260,005
Total assets	$ 94,565,394
Liabilities and Partners' Equity:	
Accounts payable (Note 3)	$ 52,085
Accrued expenses (Note 3)	575,137
Operating loan (Note 2)	200,000
Long-term debt (Note 2)	77,969,047
Total liabilities	78,796,269
Partners' equity	15,769,125
Total liabilities and partners' equity	$ 94,565,394

See notes to financial statements.

NORTHERN ELECTRIC POWER CO., L.P.

STATEMENT OF EARNINGS

FOR THE YEAR ENDED DECEMBER 31, 1999

Revenues:	
Power sales	$14,557,815
Other income	72,725
Total revenues	14,630,540
Expenses:	
General and administrative	1,309,829
Operations	401,367
Insurance	220,683
Property taxes	304,549
Depreciation and amortization	2,891,003
Interest	7,794,332
Total expenses	12,921,763
Net earnings	$ 1,708,777

See notes to financial statements.

NORTHERN ELECTRIC POWER CO., L.P.

STATEMENT OF PARTNERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 1999

	GENERAL PARTNER	LIMITED PARTNERS	TOTAL
Balance at December 31, 1998	$ (6,286)	$15,066,634	$15,060,348
Partner distributions	(10,000)	(990,000)	(1,000,000)
Net earnings	17,088	1,691,689	1,708,777
Balance at December 31, 1999	$ 802	$15,768,323	$15,769,125

See notes to financial statements.

NORTHERN ELECTRIC POWER CO., L.P.

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 1999

Cash flows from operating activities:	
Net earnings	$ 1,708,777
Adjustments to reconcile net earnings to cash provided by operating activities:	
Depreciation and amortization	2,891,003
Changes in operating assets and liabilities:	
Accounts receivable	(88,929)
Prepaid expenses and supplies	(4,082)
Accounts payable	(4,316)
Accrued expenses	21,444
Total adjustments	2,815,120
Cash provided by operating activities	4,523,897
Cash flows from investing activities:	
Purchases of property and equipment	(59,301)
Cash used in investing activities	(59,301)
Cash flows from financing activities:	
Repayment of long-term debt	(3,467,267)
Partner distributions	(1,000,000)
Cash used in financing activities	(4,467,267)
Net change in cash	(2,671)
Cash and cash equivalents, beginning of year	78,577
Cash and cash equivalents, end of year	$ 75,906
Supplemental disclosure of cash flow information:	
Cash paid during the year for interest	$ 7,794,332

See notes to financial statements.

NORTHERN ELECTRIC POWER CO., L.P.

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

a. ORGANIZATION: Northern Electric Power Co., L.P. (the "Partnership") was formed as a limited partnership under the laws of the State of New York on March 11, 1992; it organized and began business on March 1, 1994 for the purpose of developing, rehabilitating, and operating a hydroelectric facility located on the Hudson River, Town of Moreau, Saratoga County, New York. The facility began generating power on November 22, 1995. The financial statements include only the assets and liabilities which relate to the Partnership and do not include any items attributable to the partners' individual activity.

b. USE OF ESTIMATES: The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions (e.g., depreciable lives) that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

c. CASH AND CASH EQUIVALENTS: Cash includes all cash equivalents that are highly liquid investments with a maturity of three months or less when purchased.

d. PROPERTY AND EQUIPMENT: Property and equipment are carried at cost. Cost includes expenditures for construction, capitalized interest, on-site and title insurance, and attorney's costs of acquisition. The hydroelectric facilities are being depreciated on a straight-line basis over 40 years. The Partnership evaluates the recoverability of the net carrying amount of the hydroelectric facilities on an ongoing basis by reference to the anticipated future undiscounted cash flows from the operations of the project. Depreciation expense was $2,475,918 for the year ended December 31, 1999.

e. DEFERRED FINANCING COSTS: Deferred financing costs are amortized over the term of the related debt agreement (15 years).

f. INCOME TAXES: No provision has been made for federal and state income taxes because these taxes are the responsibility of the partners.

2. LONG-TERM DEBT:

Long-term debt consists of the following at December 31, 1999:

Term loan, Toronto-Dominion Bank, floating interest (7.625% at December 31, 1999), quarterly principal and interest payments of varying amounts, final maturity December 31, 2010..	$77,969,047
	===========

Collateral for the term loan and the operating line of credit discussed below includes a mortgage on all facilities, leases and rights, including the right to receive payments from Niagara Mohawk Power Corporation ("NMPC") pursuant to a Power Purchase Agreement ("PPA") with a 40-year term. The loan agreement contains various restrictive covenants including the maintenance of a minimum debt service coverage ratio.

2. LONG-TERM DEBT: (CONTINUED)

Minimum principal payments under the existing term loan agreement for the five years following December 31, 1999 and thereafter are as follows:

2000	$ 3,822,883
2001	4,667,474
2002	5,200,900
2003	5,689,873
2004	6,490,011
Thereafter	52,097,906
	$77,969,047

The Partnership also has a $5 million operating line of credit with the Toronto-Dominion Bank ("Bank") through April 2000, which automatically renews every three years through December 31, 2010. The Partnership had borrowings of $200,000 outstanding under this agreement at December 31, 1999. Borrowings under the agreement bear interest at LIBOR plus 1.875% (LIBOR was 6.44% at December 31, 1999).

To provide some degree of protection against the potential impact of rising interest rates, effective March 29, 1996, the Partnership entered into an amortizing interest rate swap agreement that expires June 29, 2006. This agreement effectively changes the Partnership's interest rate exposure on approximately 75% of the future floating rate term loan to a fixed rate. Under the agreement, each quarter the Partnership pays a fixed rate of 8.835% on the notional amount to the Bank (notional amount was $58,785,814 at December 31, 1999), and receives a variable rate from the Bank (6.18125% at December 31, 1999). The net amount payable or receivable is recorded as interest expense. At December 31, 1999, the carrying amount of all debt obligations approximate their fair values, and the fair value of the interest rate swap agreement was $4,797,300, representing the cost the Partnership would incur to terminate the agreement.

3. RELATED PARTY TRANSACTIONS:

Fees to Adirondack Hydro Development Corporation ("Adirondack"), a limited partner, during 1999 were $750,000, of which $324,144 is included in accrued expenses at December 31, 1999.

Included in accounts payable at December 31, 1999 are amounts payable to affiliated companies of $37,377.

4. POWER PURCHASE AGREEMENT:

The Partnership has entered into a 40-year power purchase agreement with NMPC, committing the parties to sell and buy, respectively, the output of the hydroelectric facility. The PPA establishes contract energy payment rates for each of the 40 years. The contract energy payment rate was $0.09002 per kilowatt hour at December 31, 1999. Revenue is recognized when the power is transmitted in accordance with the terms of the PPA.

On August 1, 1996, NMPC submitted a proposal to nineteen Independent Power Producers ("IPPs") to restructure 44 of the IPPs' PPAs with NMPC concurrent with an internal restructuring of NMPC. Adirondack's projects, including the Partnership, made up seven of the 44 PPAs subject to

4. POWER PURCHASE AGREEMENT: (CONTINUED)

NMPC's proposal. However, in June 1997, NMPC withdrew its proposal for all hydroelectric projects included in the original group of 44 PPAs. As of December 31, 1997, agreements had been reached with sixteen of the nineteen IPPs on the restructuring of 29 of the PPAs. As of March 20, 1998, the New York State Public Service Commission approved NMPC's restructuring plan. The plan included the restructuring of 29 PPAs which represent over 80% of NMPC's "out-of-market" PPAs.

Adirondack initiated separate discussions with NMPC in November 1997 regarding the restructuring of its seven PPAs. Discussions are ongoing. A term sheet was signed for two of the seven PPAs (Warrensburg Hydro Power Limited Partnership and Sissonville Limited Partnership) in 1999. Adirondack management anticipates that a final settlement for the restructuring of the remaining PPAs will be reached in 2000.

5. LEASES

The Partnership leases the land upon which its hydroelectric facilities are situated from NMPC and the adjacent riverbed from the State of New York. These lease agreements extend through the end of the PPA with NMPC. Total rental expense in 1999 was $60,349.

NORTHERN ELECTRIC POWER CO., L.P.

BALANCE SHEET

SEPTEMBER 30, 2000 (UNAUDITED)

Assets:	
Cash	$ 2,382,160
Accounts receivable	1,175,127
Prepaid expenses and supplies	233,559
Total current assets	3,790,846
Property and equipment:	
Hydroelectric facilities	99,037,055
Less accumulated depreciation	(12,142,317)
Property and equipment, net	86,894,738
Deferred financing costs	3,965,082
Total assets	$ 94,650,666
Liabilities and Equity:	
Accounts payable	$ 1,707
Accrued expenses	2,099,741
Total current liabilities	2,101,448
Term debt--Toronto Dominion	75,101,885
Partners' equity	17,447,333
Total liabilities and equity	$ 94,650,666

NORTHERN ELECTRIC POWER CO., L.P.

STATEMENTS OF INCOME

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Revenue:		
Electricity sales	$16,504,955	$11,309,072
Expenses:		
Operations	1,393,350	1,278,130
Administrative and general	198,299	267,111
Depreciation/amortization	2,152,531	2,168,612
Taxes other than income	348,954	217,411
Total expenses	4,093,134	3,931,264
Miscellaneous non-operating income	100,554	60,367
Interest expense	5,734,167	5,862,561
Net earnings	$ 6,778,208	$ 1,575,614

NORTHERN ELECTRIC POWER CO., L.P.

STATEMENTS OF CASH FLOWS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Cash flows from operating activities:		
Net earnings	$ 6,778,208	$ 1,575,614
Adjustments to reconcile net earnings to cash provided by (used in) operating activities:		
Depreciation and amortization	2,152,531	2,168,612
Changes in operating assets and liabilities:		
Accounts receivable	(125,314)	89,218
Prepaid expenses and supplies	193,766	197,763
Accounts payable	(50,378)	20,302
Accrued partner distribution payable	(1,500,000)	--
Accrued expenses	1,524,603	(156,733)
Total adjustments	2,195,208	2,319,162
Cash provided by operating activities	8,973,416	3,894,776
Cash flows from investing activities:		
Purchases of property and equipment	--	(60,660)
Cash used in investing activities	--	(60,660)
Cash flows from financing activities:		
Repayment of operating loan	(200,000)	(200,000)
Repayment of long-term debt	(2,867,162)	(2,600,450)
Partner distributions	(3,600,000)	(1,000,000)
Cash used in financing activities	(6,667,162)	(3,800,450)
Net change in cash	2,306,254	33,666
Cash and cash equivalents, beginning of period	75,906	78,577
Cash and cash equivalents, end of period	$ 2,382,160	$ 112,243

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of South Glens Falls
Limited Partnership

In our opinion, the accompanying balance sheet and the related statements of earnings, of partners' equity and of cash flows present fairly, in all material respects, the financial position of South Glens Falls Limited Partnership (the "Partnership") at December 31, 1999, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Milwaukee, Wisconsin

February 25, 2000

SOUTH GLENS FALLS LIMITED PARTNERSHIP

BALANCE SHEET

DECEMBER 31, 1999

Assets:	
Cash and cash equivalents (Note 1)	$ 76,870
Accounts receivable--power sales	388,237
Prepaid expenses and supplies	180,734
Property and equipment:	
Hydroelectric facilities (Notes 1 and 2)	39,428,866
Less accumulated depreciation	(5,338,783)
Property and equipment, net	34,090,083
Deferred financing costs, net of accumulated amortization of $710,666 (Note 1)	1,257,331
Total assets	$35,993,255
Liabilities and Partners' Equity:	
Accounts payable (Note 3)	$ 43,426
Accrued expenses (Note 3)	369,158
Operating loan (Note 2)	100,000
Long-term debt (Note 2)	28,064,527
Total liabilities	28,577,111
Partners' equity	7,416,144
Total liabilities and partners' equity	$35,993,255

See notes to financial statements.

SOUTH GLENS FALLS LIMITED PARTNERSHIP

STATEMENT OF EARNINGS

FOR THE YEAR ENDED DECEMBER 31, 1999

Revenues:	
Power sales	$5,372,443
Other income	29,031
Total revenues	5,401,474
Expenses:	
General and administrative	658,607
Operations	201,096
Insurance	101,496
Property taxes	158,351
Depreciation and amortization	1,121,800
Interest	2,280,426
Total expenses	4,521,776
Net earnings	$ 879,698

See notes to financial statements.

SOUTH GLENS FALLS LIMITED PARTNERSHIP

STATEMENT OF PARTNERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 1999

	GENERAL PARTNER	LIMITED PARTNERS	TOTAL
Balance at December 31, 1998	$ 5,108	$6,731,338	$6,736,446
Partner distributions	(2,000)	(198,000)	(200,000)
Net earnings	8,797	870,901	879,698
Balance at December 31, 1999	$11,905	$7,404,239	$7,416,144

See notes to financial statements.

SOUTH GLENS FALLS LIMITED PARTNERSHIP

STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED DECEMBER 31, 1999

Cash flows from operating activities:	
Net earnings	$ 879,698
Adjustments to reconcile net earnings to cash provided by operating activities:	
Depreciation and amortization	1,121,800
Changes in operating assets and liabilities:	
Accounts receivable	(41,472)
Prepaid expenses and supplies	(644)
Accounts payable	19,155
Accrued expenses	190,714
Total adjustments	1,289,553
Cash provided by operating activities	2,169,251
Cash flows from financing activities:	
Repayment of long-term debt	(2,010,908)
Partner distributions	(200,000)
Net proceeds from operating loans	100,000
Cash used in financing activities	(2,110,908)
Net change in cash	58,343
Cash and cash equivalents, beginning of year	18,527
Cash and cash equivalents, end of year	$ 76,870
Supplemental disclosure of cash flow information:	
Cash paid during the year for interest	$ 2,280,426

See notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

a. ORGANIZATION: South Glens Falls Limited Partnership (the "Partnership") was formed as a limited partnership under the laws of the State of New York on March 11, 1992; it organized and began business on August 24, 1993 for the purpose of developing, rehabilitating, and operating a hydroelectric facility located on the Hudson River in the Village of South Glens Falls, Saratoga County, New York. The Partnership began generating power on August 11, 1994. The financial statements include only the assets and liabilities which relate to the Partnership and do not include any items attributable to the partners' individual activity.

b. USE OF ESTIMATES: The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions (e.g., depreciable lives) that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

c. CASH AND CASH EQUIVALENTS: Cash includes all cash equivalents that are highly liquid investments with a maturity of three months or less when purchased.

d. PROPERTY AND EQUIPMENT: Property and equipment are carried at cost. Cost includes expenditures for construction, capitalized interest, on-site and title insurance, and attorney's costs of acquisition. The hydroelectric facilities are being depreciated on a straight-line basis over 40 years. The Partnership evaluates the recoverability of the net carrying amount of the hydroelectric facilities on an ongoing basis by reference to the anticipated future undiscounted cash flows from the operations of the project. Depreciation expense was $985,722 for the year ended December 31, 1999.

e. DEFERRED FINANCING COSTS: Deferred financing costs are amortized over the term of the related debt agreement (15 years).

f. INCOME TAXES: No provision has been made for federal and state income taxes because these taxes are the responsibility of the partners.

2. LONG-TERM DEBT:

Long-term debt consists of the following at December 31, 1999:

Term loan, Toronto-Dominion Bank, floating interest (7.625% at December 31, 1999), quarterly principal and interest payments of varying amounts, final maturity December 31, 2009	$28,064,527

Collateral for the term loan and the operating line of credit discussed below includes a mortgage on all land and facilities, leases and rights, including the right to receive payments from Niagara Mohawk Power Corporation ("NMPC") pursuant to a Power Purchase Agreement ("PPA") with a 40-year term. The loan agreement contains various restrictive covenants including the maintenance of a minimum debt service coverage ratio.

2. LONG-TERM DEBT: (CONTINUED)

Minimum principal payments under the existing term loan agreement for the five years following December 31, 1999 and thereafter are as follows:

2000	$ 1,940,351
2001	2,116,746
2002	2,257,863
2003	2,434,258
2004	2,628,293
Thereafter	16,687,016
	$28,064,527

The Partnership also has a $2.5 million operating line of credit with the Toronto-Dominion Bank ("Bank") through March 7, 2001, which can be renewed each year through December 31, 2009. The Partnership had borrowings of $100,000 outstanding under this agreement at December 31, 1999. Borrowings under the agreement bear interest at LIBOR plus 1.875% (LIBOR was 6.44% at December 31, 1999).

To provide some degree of protection against the potential impact of rising interest rates, effective February 3, 1995, the Partnership entered into an amortizing interest rate swap agreement with the Bank that expires December 31, 2004. This agreement effectively changes the Partnership's interest rate exposure on approximately 70% of the future floating rate term loan to a fixed rate. Under the agreement, each quarter the Partnership pays a fixed rate of 6.375% on the notional amount to the Bank (notional amount was $19,887,500 at December 31, 1999), and receives a variable rate from the Bank (6.18375% at December 31,1999). The net amount payable or receivable is recorded as interest expense. At December 31, 1999, the carrying amount of all debt obligations approximate their fair values, and the fair value of the interest rate swap agreement was $339,093, representing the amount the Partnership would receive if the agreement was terminated.

3. RELATED PARTY TRANSACTIONS:

Fees to Adirondack Hydro Development Corporation ("Adirondack"), a limited partner, during 1999 were $375,000, of which $187,500 is included in accrued expenses at December 31, 1999.

Included in accounts payable at December 31, 1999 is $18,070, payable to affiliated companies.

4. POWER PURCHASE AGREEMENT:

The Partnership has entered into a 40-year power purchase agreement with NMPC, committing the parties to sell and buy, respectively, the output of the hydroelectric facility. The PPA establishes contract energy payment rates for each of the 40 years. The contract payment rate was $0.09182 per kilowatt hour at December 31, 1999. Revenue is recognized when the power is transmitted in accordance with the terms of the PPA.

On August 1, 1996, NMPC submitted a proposal to nineteen Independent Power Producers ("IPPs") to restructure 44 of the IPPs' PPAs with NMPC concurrent with an internal restructuring of NMPC. Adirondack's projects, including the Partnership, made up seven of the 44 PPAs subject to NMPC's proposal. However, in June 1997, NMPC withdrew its proposal for all hydroelectric projects

4. POWER PURCHASE AGREEMENT: (CONTINUED)

included in the original group of 44 PPAs. As of December 31, 1997, agreements had been reached with sixteen of the nineteen IPPs on the restructuring of 29 of the PPAs. As of March 20, 1998, the New York State Public Service Commission approved NMPC's restructuring plan. The plan included the restructuring of 29 PPAs which represent over 80% of NMPC's "out-of-market" PPAs.

Adirondack initiated separate discussions with NMPC in November 1997 regarding the restructuring of its seven PPAs. Discussions are ongoing. A term sheet was signed for two of the seven PPAs (Warrensburg Hydro Power Limited Partnership and Sissonville Limited Partnership) in 1999. Adirondack management anticipates that a final settlement for the restructuring of the remaining PPAs will be reached in 2000.

5. LEASES:

The Partnership leases the land upon which its hydroelectric facilities are situated from NMPC and the adjacent riverbed from the State of New York. These lease agreements extend through the end of the PPA with NMPC. Total rental expense in 1999 was $98,746.

SOUTH GLENS FALLS LIMITED PARTNERSHIP

BALANCE SHEET

SEPTEMBER 30, 2000 (UNAUDITED)

Assets:	
Cash	$ 941,921
Accounts receivable	415,103
Prepaid expenses and supplies	137,182
Total current assets	1,494,206
Property and equipment:	
Hydroelectric facilities	39,428,866
Less accumulated depreciation	(6,078,074)
Property and equipment, net	33,350,792
Deferred financing costs	1,158,931
Total assets	$36,003,929
Liabilities and Equity:	
Accounts payable	$ 3,350
Accrued expenses	665,025
Term debt--Toronto Dominion	26,609,263
Total liabilities	27,277,638
Partners' equity	8,726,291
Total liabilities and partners' equity	$36,003,929

SOUTH GLENS FALLS LIMITED PARTNERSHIP

STATEMENTS OF INCOME

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Revenue:		
Electricity sales	$5,868,821	$4,172,908
Expenses:		
Operations	603,758	572,430
Administrative and general	99,634	138,568
Depreciation/amortization	837,691	841,350
Taxes other than income	123,931	118,752
Total expenses	1,665,014	1,671,100
Miscellaneous non-operating income	38,977	24,230
Interest expense	1,682,637	1,717,396
Net earnings	$2,560,147	$ 808,642

SOUTH GLENS FALLS LIMITED PARTNERSHIP

STATEMENTS OF CASH FLOWS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2000 AND 1999 (UNAUDITED)

	2000	1999
Cash flows from operating activities:		
Net earnings	$ 2,560,147	$ 808,642
Adjustments to reconcile net earnings to cash provided by operating activities:		
Depreciation and amortization	837,691	841,350
Changes in operating assets and liabilities:		
Accounts receivable	(26,866)	19,617
Prepaid expenses and supplies	43,552	43,134
Accounts payable	(40,076)	(5,075)
Accrued partner distribution payable	(450,000)	--
Accrued expenses	295,867	32,081
Total adjustments	660,168	931,107
Cash provided by operating activities	3,220,315	1,739,749
Cash flows from financing activities:		
Repayment of operating loan	(100,000)	--
Repayment of long-term debt	(1,455,264)	(1,508,181)
Partner distributions	(800,000)	(200,000)
Cash used in financing activities	(2,355,264)	(1,708,181)
Net change in cash	865,051	31,568
Cash and cash equivalents, beginning of period	76,870	18,527
Cash and cash equivalents, end of period	$ 941,921	$ 50,095

[LOGO]