

BROWN TOM INC /DE
Form 10-K/A
August 05, 2003

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K/A

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

For the Fiscal Year Ended December 31, 2002

or

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

For the Transition Period from _____ to _____
Commission File Number 001-31308

Tom Brown, Inc.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction
of incorporation or organization)

95-1949781
(I.R.S. Employer Identification No.)

555 Seventeenth Street
Suite 1850
Denver, Colorado
(Address of principal executive offices)

80202
(Zip Code)

303-260-5000

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act: **None**

Securities Registered Pursuant to Section 12(g) of the Act:

Common Stock, \$.10 par Value
Convertible Preferred Stock, \$.10 par Value
(Title of Class)

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

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

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes No

The aggregate market value of the Registrant's Common Stock held by non-affiliates was approximately \$944,162,050 as of June 28, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 11, 2003, there were 39,398,903 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2003 Annual Meeting of Stockholders to be held on May 8, 2003 are incorporated by reference into Part III.

TOM BROWN, INC.

FORM 10-K

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EXPLANATORY NOTE

Tom Brown, Inc. (the "Company") is filing this amendment in response to comments received from the Securities and Exchange Commission regarding the Company's Annual Report on Form 10-K/A for the fiscal year ended December 31, 2002 that was originally filed on March 25, 2003. This report significantly revises the disclosures pertaining to the Company's business, the Company's properties, the Company's legal proceedings, management's discussion and analysis of financial condition and results of operations, and the Company's financial statements. This report continues to speak as of the date of the original filing, and the Company has not updated the disclosure in this report to speak as of a later date. All information contained in this report and the original filing is subject to updating and supplementing as provided in the Company's periodic reports filed with the Securities and Exchange Commission.

PART I**ITEM 1. Business****GENERAL**

Tom Brown, Inc. (the "Company") was organized in 1955 as a privately-owned drilling company known as Scarber-Brown Drilling Company and in 1959 as Tom Brown Drilling Company, Inc. In 1968, the Company merged into Gold Metals Consolidated Mining Company, a publicly-traded Nevada corporation. The name of the Company after the merger was changed to Tom Brown Drilling Company, Inc. and to Tom Brown, Inc. in 1971. In February 1987, the Company changed its state of incorporation from Nevada to Delaware. In 1999, the Company relocated its headquarters and executive offices to 555 Seventeenth Street, Suite 1850, Denver, Colorado 80202 and its telephone number at that address is (303) 260-5000. Unless the context otherwise requires, all references to the "Company" include Tom Brown, Inc. and its subsidiaries.

The Company is engaged primarily in the exploration for, and the acquisition, development, production, marketing and sale of, natural gas, natural gas liquids and crude oil in North America. The Company's activities are conducted principally in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Utah and Colorado, the Val Verde Basin and Permian Basin of west Texas and southeastern New Mexico, the east Texas Basin and the western Canadian Sedimentary Basin. The Company also, to a lesser extent, conducts exploration and development activities in other areas of the continental United States and Canada.

In December 2000, the Company initiated a cash tender for all the outstanding stock of Stellarton Energy Corporation ("Stellarton"). This transaction was completed on January 12, 2001.

The Company's industry segments are (i) the exploration for, and the acquisition, development and production of, natural gas, natural gas liquids and crude oil, (ii) the marketing, gathering, processing and sale of natural gas and (iii) the drilling of gas and oil wells.

Except for its gas and oil leases with governmental entities and other third parties who enter into gas and oil leases or assignments with the Company in the regular course of its business and options to purchase gas and oil leases with the Eastern Shoshone and Northern Arapaho Tribes, the Company has no material patents, licenses, franchises or concessions that it considers significant to its gas and oil operations.

The nature of the Company's business is such that it does not maintain or require a substantial amount of products, customer orders or inventory. The Company's gas and oil operations are not subject to renegotiations of profits or termination of contracts at the election of the federal government.

The Company has not been a party to any bankruptcy, receivership, reorganization or similar proceeding, except in connection with its participation as a joint proponent of a plan of reorganization for Presidio Oil Company in 1996.

BUSINESS STRATEGY

The Company's business strategy is to increase stockholder value through the discovery, acquisition and development of long-lived gas and oil reserves in areas where the Company has industry knowledge and operations expertise. The Company's principal investments have been in natural gas prone basins, which the Company believes will continue to provide the opportunity to accumulate significant long-lived gas and oil

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reserves at attractive prices. The expansion into Canada in 2001 was an extension of this fundamental strategy.

The Company's year-end domestic acreage position was approximately 2,677,000 gross (1,773,000 net) acres (including options) located primarily in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, the Paradox Basin of Colorado and Utah, and the Permian, Val Verde and east Texas Basins of Texas where the Company can utilize its geological and technical expertise and its control of operations for the further development and expansion of these areas. Approximately 89% of the net acreage is undeveloped.

The Company's year-end Canadian acreage position located in western Alberta was approximately 540,000 gross (359,000 net) acres. Approximately 78% of the net acreage is undeveloped.

Additionally, by staying focused in its core basins, the Company continues to develop more effective drilling and completion techniques which can improve overall economic efficiency.

The Company increased its reserves in 2002 over 2001 by 2% due primarily to continued drilling success in its core areas. Year-end proved reserves were 750 billion cubic feet equivalent ("Bcfe"), compared to year-end 2001 reserves of 732 Bcfe. At December 31, 2002, the Canadian reserve base was 82 Bcfe compared to 77 Bcfe at December 31, 2001. Since December 31, 1995, the Company has increased proved reserves at a compounded annual growth rate of 22%, or from 188 Bcfe to 750 Bcfe.

Reserve replacement for 2002 was 137% from all sources and 119% from extensions, discoveries and revisions only. The Company's reserve to production ratio was 8.8 years at year-end 2002 compared to 9.6 years at year-end 2001. In addition to increasing reserves, the Company also increased its production 12% from 76.4 Bcfe in 2001 to 85.5 Bcfe in 2002.

The Company markets a majority of its operated gas production and some third party gas in the Rocky Mountains through Retex, Inc. ("Retex"), the Company's wholly-owned marketing subsidiary.

The Company also conducts gas gathering and processing activities in the Rocky Mountain area. Initially, these functions were conducted through Wildhorse Energy Partners, LLC ("Wildhorse") which was owned 55% by Kinder Morgan, Inc. ("KM") and 45% by the Company. In November 2000, the Wildhorse gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the Wildhorse storage facility and a cash payment of \$14.7 million. TBI Field Services, Inc. ("TBIFS") was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer these gathering and processing assets. In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution, retaining only those gathering systems considered integral to the Company's gas and oil reserve base. As the Company directly owns and operates several gas processing and gathering systems adjacent to its areas of operations, the systems ultimately retained by TBIFS after the Wildhorse dissolution were merged into the Company's operations in 2002 and TBIFS ceased to function as a separate entity.

The Company plans to continue to selectively pursue acquisitions of gas and oil properties in its core areas of activity and, in connection therewith, the Company from time to time will be involved in evaluations of, or discussions with, potential acquisition candidates. The consideration for any such acquisition might involve the payment of cash and/or the issuance of equity or debt securities.

Notwithstanding the Company's historical ability to implement the above strategy, the Company may not be able to successfully implement its strategy in the future. See "Risk Factors."

AREAS OF ACTIVITY

The following discussion focuses on areas the Company considers to be its core areas of operations and those that offer the Company the greatest opportunities for further exploration and development activities.

Wind River, Green River, Paradox, and Piceance Basins

The Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado, and the Paradox Basin of Colorado and Utah account for the major portion of the Company's current and anticipated domestic exploration and development activities with approximately 74% of the Company's proved reserves at December 31, 2002. The Company owns interests in 1,278 producing wells in these basins that averaged net daily production of 159 Mmcfe for 2002. The Company has approximately 1,565,000 gross (1,224,000 net) developed and undeveloped acres in these basins, including option acreage of approximately 281,000 gross undeveloped (253,000 net) acres in the Wind River Basin.

In 2002, the Company drilled and completed 16 wells in the Wind River basin, the majority of which were located in the Pavillion field where the Company holds a 92% working interest. In the Piceance basin, the Company drilled 26 wells in 2002 (completing 25). The Piceance wells were principally drilled at the Company's 100% owned White River Dome coal bed methane project in western Colorado.

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The Rocky Mountain region has experienced limited natural gas transportation capacity. Recognizing these restrictions, various pipelines have constructed lines and are continuing to add additional pipeline capacity into this area.

Permian and Val Verde Basins

The Permian and Val Verde Basins accounted for approximately 9% of the Company's proved reserves at December 31, 2002. The Company's share of production from these basins averaged 28 Mmcfe/d for 2002. The Company holds between 30% to 50% working interests in approximately 46,800 gross (20,300 net) acres in the Val Verde Basin. The Permian Basin contains significant oil reserves for the Company, located primarily in the Sprayberry Field.

In the Deep Valley exploration project area of the Permian Basin, the Company drilled a horizontal Montoya well in 2001 which tested non-commercial in the Montoya formation but will be tested in the Devonian formation in 2003. In 2002, the Company successfully completed a Devonian well in this area with a 50% working interest that commenced production in June 2002 at initial rates approximating 10 Mmcfe/d declining to 2.5 Mmcfe/d in early 2003. Two wells were drilled subsequent to this discovery in 2002 that are currently being evaluated. The Company also attempted a horizontal re-entry in Deep Valley to test the Devonian section of a well in 2002 that was unsuccessful.

East Texas Basin

The Company participates in a continuing developmental drilling program in the Mimms Creek Field (Bossier Sands play) in Freestone County, Texas. During 2002, 11 wells were drilled and completed under this program, with the Company owning working interests ranging from 50% to 62.5%.

In recent years, the Company has acquired approximately 80,000 net acres in the James Lime (horizontal) Trend of the east Texas Basin. In 2001, the Company drilled seven wells in the James Lime (horizontal) Trend of which five were initially completed. This large regional play is in its early stages of development and the Company is working to determine its potential based upon the initial production rates and variable decline rates of the wells drilled to date.

Canada

The western Canadian Sedimentary Basin accounted for approximately 11% of the Company's proved reserves at December 31, 2002. The Company's share of production from these basins averaged 24 Mmcfe/d in 2002. The Company owns interests in 252 wells and has approximately 540,000 gross (359,000 net) developed and undeveloped acres in this area. In 2002, the Company drilled 13 wells in Canada of which 12 were completed. These wells were primarily located in the Carrot Creek and Edson fields operated by the Company.

BUSINESS DEVELOPMENTS

Current Developments in the Gas and Oil Business

Acquisition of Stellarton Energy Corporation

Effective January 16, 2001, the Company purchased 100% of Stellarton Energy Corporation ("Stellarton") for \$95 million. The acquisition was funded through a five-year Canadian term loan. Stellarton's assets are located in western Alberta, Canada with estimated total net proved reserves (after royalty) of 58.8 billion cubic feet (Bcf) of gas and 2.82 million barrels of oil and natural gas liquids for total equivalent proved reserves of 75.5 Bcfe, as of the date of this acquisition. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Debt" for a description of the material terms of the Company's bank credit facility, including the Canadian term loan.

Acquisition of Rocky Mountain Assets

In June 2002, the Company purchased Rocky Mountain gas and oil properties located within the Greater Green River Basin of Wyoming for approximately \$8.1 million from an unrelated third party. In December 2002, the Company acquired additional assets within this basin from this seller for \$6.8 million. The acquisition cost of both of these transactions was net of normal closing adjustments. The acquired interests from these two transactions included an estimated 12.7 Bcfe of proved reserves.

In June 2000, the Company purchased an additional working interest in the Company-operated Pavillion Field in the Wind River Basin in Wyoming. The Company acquired the additional interest from State Farm Mutual Automobile Insurance Company, a stockholder of the Company. The acquired interests included an estimated 24 Bcfe of proved reserves purchased for total consideration of \$15.2 million net of normal closing adjustments.

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Acquisition of the Assets of Unocal Corporation

In July 1999, the Company completed an acquisition of substantially all of the Rocky Mountain oil and gas assets of Unocal Corporation ("Unocal") for 5.8 million shares of common stock and \$5 million in cash for a total purchase price of \$68.5 million (\$60.9 million after deducting normal purchase price adjustments).

The Unocal oil and gas assets are primarily located in the Paradox Basin of southwestern Colorado and southeastern Utah. These assets and properties compliment the Company's 163,000 net undeveloped acres in the Paradox Basin.

Included in the acquisition was the Lisbon Plant, a modern sophisticated cryogenic (60 million cubic feet per day capacity) natural gas processing plant that extracts natural gas liquids and merchantable helium; and separates carbon dioxide, hydrogen sulfide and nitrogen from the raw gas stream. The net proved reserves of these Unocal properties were estimated to be 93.2 billion cubic feet equivalent of gas as of the closing date of July 1, 1999. Approximately 65,000 net undeveloped acres were also acquired.

Current Developments in the Marketing, Gathering and Processing Business

In September 1999, KM became the operator of, and 55% partner in, Wildhorse as a result of a merger with KN Energy, Inc. ("KNE"). Wildhorse was formed in connection with the Company's 1996 acquisition of KN Production Company, the wholly-owned oil and gas production subsidiary of KNE. Wildhorse was created to provide services related to natural gas, natural gas liquids and other natural gas products, including gathering, processing and storage services and field services. The Company owned 45% of Wildhorse since its inception. Effective September 1, 1999, Wildhorse assigned 100% of its marketing operations to Retex, the Company's wholly-owned marketing subsidiary. Additionally, firm transportation contracts were assigned 55% to KM and 45% remained in Retex. In November 2000, the Wildhorse gathering and processing assets were distributed to the Company in anticipation of the dissolution of Wildhorse. KM received the Wildhorse storage facility and a cash payment of \$14.7 million. "TBIFS" was formed as a wholly-owned subsidiary of Tom Brown, Inc. to administer the gathering and processing assets received in this distribution.

In 2001, TBIFS selectively sold many of the gathering and processing facilities received in the Wildhorse asset distribution. The systems sold were considered non-strategic to the Company's operations and, as these divestitures were part of the Wildhorse integration process, the net cash proceeds of \$24.0 million were recorded as a reduction to the investment in gathering assets. After these divestitures, the only significant asset retained was the Wind River gathering system in one of the Company's core areas. In 2002, the Company liquidated TBIFS to transfer the remaining gathering and processing assets to Tom Brown, Inc.

Current Developments in the Drilling Business

Acquisition of Assets of W. E. Sauer Companies, LLC

On January 7, 1998, the Company completed the acquisition of all of the drilling assets of W. E. Sauer Companies L.L.C. of Casper, Wyoming for approximately \$8.1 million. The Company operates the assets in its subsidiary, Sauer Drilling Company ("Sauer"), and plans to continue to serve the drilling needs of operators in the central Rocky Mountain region in addition to drilling for the Company. The assets included five drilling rigs, tubular goods, a yard and related assets. Subsequent to the acquisition, Sauer has acquired three additional drilling rigs for approximately \$4 million.

MARKETS

The Company's gas production has historically been sold primarily under month-to-month contracts with marketing companies and local distribution companies (LDC's). During 2001 and 2002, there was a significant amount of volatility in the prices received for natural gas. Monthly closing gas prices in 2001 as measured on the New York Mercantile Exchange ("NYMEX") varied from a high of \$9.98 per million British thermal unit ("Mmbtu") for January 2001 to a low of \$1.83 per Mmbtu for October 2001. In 2002, the NYMEX gas prices varied from a high of \$4.14 per Mmbtu in December 2002 to a low of \$2.01 per Mmbtu in February 2002. The U.S. Rocky Mountain region represented approximately 68% of the Company's 2002 gas production and 66% of its 2001 production. The price of gas in the Rocky Mountains at the Colorado Interstate Gas (CIG) hub was \$1.25 and \$.77 per Mmbtu below the NYMEX posted gas price on average for 2002 and 2001, respectively. The Company's Canadian production base has also been subject to price volatility. In 2001, gas production from the Canadian fields was subject to gas pricing that ranged from \$1.10 per Mmbtu above the February 2001 NYMEX price to a price that was \$.98 per Mmbtu below the October 2001 NYMEX price. In 2002, the Canadian gas prices continued to be volatile ranging from \$.12 per Mmbtu below the NYMEX posting for February 2002 to \$1.24 below the August 2002 NYMEX price.

The Company markets most of its oil production with independent third-party resellers and refiners at market ("posted") prices. These posted prices generally reflect the prices determined by the trading of West Texas Intermediate ("WTI") oil futures contracts on the NYMEX, with adjustments due to basis differential and for the quality of oil produced.

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NYMEX prices for both gas and oil are influenced by weather, seasonal demand, levels of storage, production levels and a variety of political and economic factors over which the Company has no control. See "Risk Factors."

Production Volumes, Unit Prices and Costs

The following table sets forth certain information regarding the Company's volumes of production sold and average prices received associated with its production and sales of natural gas, natural gas liquids and crude oil for each of the years ended December 31, 2002, 2001 and 2000.

<i>United States</i>	Years Ended December 31,		
	2002	2001	2000
Production Volumes:			
Natural Gas (MMcf)	65,781	57,163	51,199
Crude Oil (MBbls)	623	723	773
Natural Gas Liquids (MBbls)	1,189	1,074	1,074
Net Average Daily Production Volumes:			
Natural Gas (Mcf)	180,221	156,611	139,888
Crude Oil (Bbls)	1,708	1,979	2,113
Natural Gas Liquids (Bbls)	3,258	2,943	2,934
Average Sales Prices:			
Natural Gas (per Mcf):			
Price received	\$ 2.10	\$ 3.43	\$ 3.46
Effect of hedges	\$	\$ 0.30	\$
Net sales price	\$ 2.10	\$ 3.73	\$ 3.46
Crude Oil (per Bbl)	\$ 23.20	\$ 22.64	\$ 28.05
Natural Gas Liquids (per Bbl)	\$ 11.39	\$ 13.25	\$ 16.77
Average Production Cost (per Mcfe)(1)	\$.57	\$.70	\$.76

<i>Canada</i>	Years Ended December 31,	
	2002	2001
Production Volumes:		
Natural Gas (MMcf)	6,386	6,661
Crude Oil (Mbbls)	220	158
Natural Gas Liquids (Mbbls)	193	143
Net Average Daily Production Volumes:		
Natural Gas (Mcf)	17,496	18,247
Crude Oil (Bbls)	601	432
Natural Gas Liquids (Bbls)	529	392
Average Sales Prices:		
Natural Gas (per Mcf):		
Price received	\$ 3.07	\$ 3.49
Effect of hedges	\$ (0.03)	\$
Net sales price	\$ 3.04	\$ 3.49
Crude Oil (per Bbl)	\$ 23.86	\$ 25.11
Natural Gas Liquids (per Bbl)	\$ 16.17	\$ 20.23
Average Production Cost (per Mcfe)(1)	\$.55	\$.62

- (1) Includes production costs and taxes on production. (Mcf means one thousand cubic feet of natural gas equivalent, calculated on the basis of six barrels of oil and natural gas liquids to one Mcf of gas.)

Customers

Gas and oil sales to ConocoPhillips, Inc. accounted for 17% of the Company's gas and oil sales for the year ended December 31, 2002. No other purchaser accounted for 10% or more of the Company's total gas and oil revenue during 2002. Because there are numerous other parties available to purchase the Company's production, the Company believes the loss of ConocoPhillips would not materially affect its ability to sell natural gas or crude oil.

In 2002, a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling \$6.2 million. In the fourth quarter of 2002, the Company received a \$1.4 million cash settlement in connection with this default. For additional information, please see Note 10 Related Parties and Significant Customers in the Notes to the Company's Consolidated Financial Statements.

Competition

The Company encounters strong competition from major oil companies and independent operators in acquiring properties and leases for the exploration for, and the development and production of, natural gas and crude oil. Competition is particularly intense with respect to the acquisition of desirable undeveloped gas and oil leases. The principal competitive factors in the acquisition of undeveloped gas and oil leases include the availability and quality of staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of the Company's competitors have financial resources, staffs and facilities substantially greater than those of the Company. In addition, the producing, processing and marketing of natural gas and crude oil is affected by a number of factors which are beyond the control of the Company, the effect of which cannot be accurately predicted. See "Risk Factors."

The principal raw materials and resources necessary for the exploration and development of natural gas and crude oil are leasehold prospects under which gas and oil reserves may be discovered, drilling rigs and related equipment to drill for and produce such reserves and knowledgeable personnel

to conduct all phases of gas and oil operations. The Company must compete for such raw materials and resources with both major oil companies and independent operators.

Retex encounters competition from other natural gas transportation and marketing entities in the marketing of gas. Such competition may materially affect the volumes and margins that Retex may derive.

Employees

At December 31, 2002, the Company had 429 employees of which 103 were employed by Sauer. None of the Company's employees are represented by labor unions or covered by any collective bargaining agreement. The Company considers its relations with its employees to be satisfactory.

REGULATION UNITED STATES

Regulation of Gas and Oil Production

Gas and oil operations are subject to various types of regulation by state and federal agencies. Legislation affecting the gas and oil industry is under constant review for amendment or expansion. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. The regulatory burden on the gas and oil industry increases the Company's cost of doing business and, consequently, affects its profitability.

States in which the Company conducts its gas and oil activities regulate the production and sale of natural gas and crude oil, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of gas and oil resources. In addition, most states regulate the rate of production and may establish maximum daily production allowables for wells on a market demand or conservation basis.

Gas Price Controls

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Prior to January 1993, certain natural gas sold by the Company was subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 ("NGPA"). The NGPA prescribed maximum lawful prices for natural gas sales effective December 1, 1978. Effective January 1, 1993, natural gas prices were completely deregulated and sales of the Company's natural gas are now made at market prices. The majority of the Company's gas sales contracts either contain decontrolled price provisions or already provide for market prices.

Oil Price Controls

Sales of crude oil, condensate and gas liquids by the Company are not regulated and are made at market prices.

Environmental Regulation

The Company's natural gas and oil exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (EPA), issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from the Company's operations. The regulatory burden on the natural gas and oil industry increases the cost of doing business and consequently affects profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect the Company's operations and financial position, as well as the gas and oil industry in general. Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and the Company has not experienced any material adverse effect from compliance with these environmental requirements; this trend, however, may not continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or Superfund, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Rocno Corporation, a wholly owned subsidiary of the Company, has been identified as a potentially responsible party, or PRP, at the Sheridan Superfund Site in Waller County, Texas. However, given the large number of PRPs identified at this site, as well as Rocno's relatively small proportionate share of estimated cleanup costs for the site, management of the Company does not expect that Rocno's participation in the cleanup of the Sheridan Superfund Site will have a material adverse effect on the Company's operations. See "Item 3. Legal Proceedings."

The Resource Conservation and Recovery Act (RCRA), as amended, generally does not regulate most wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous waste. Although the costs of managing solid and hazardous waste may be significant, the Company does not expect to experience more burdensome costs than similarly situated companies involved in natural gas and oil exploration and production.

The Company currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of gas and oil. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial plugging or pit closure operations to prevent future contamination.

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit

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issued by the EPA or the state. These proscriptions also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Company's management believes that the Company has obtained or applied for all permits required under the Clean Water Act. Sanctions for failure to comply with Clean Water Act requirements include administrative, civil and criminal penalties, as well as injunctive relief.

The Clean Air Act (CAA), as amended, restricts the emission of air pollutants from many sources, including natural gas and oil operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. The Company's management believes that the Company is in substantial compliance with all air emissions regulations and that the Company has or has applied for all necessary permits for its operations. Management also believes that air emission permits for operation of the Company's Pavillion Gas Plant in Fremont County, Wyoming and Lisbon Gas Plant in Moab, Utah are material to the Company's operations. Currently, the Pavillion Gas Plant holds a Title V air emission operating permit that will not expire until January 9, 2009. The Lisbon Gas Plant is expected to be issued a Title V air emissions operating permit in the third quarter of 2003 and, until it receives the Title V permit, continues to operate under a state-issued Approval Order that allows the facility to conduct operations under the state permit until such time as the Title V permit is issued. The Title V permit, once issued, is expected to have an initial term of at least five years, and renewals and extensions of air emissions permits are routinely granted. The costs associated with obtaining and maintaining these permits are not material.

Indian Lands

The Company's Muddy Ridge and Pavillion Fields are located on the Wind River Indian Reservation. The Eastern Shoshone and Northern Arapaho Tribes levy taxes on the production of hydrocarbons. The Bureau of Indian Affairs, Minerals Management Service and Bureau of Land Management of the U.S. Department of the Interior perform certain regulatory functions relating to operation of Indian gas and oil leases. The Company owns interests in three leases in the Pavillion Field which were issued pursuant to the provisions of the Act of August 21, 1916, for initial terms of 20 years each, with a preferential right by the lessee to renew the leases for subsequent ten-year terms. The leases were renewed for an additional ten-year term in 1992, effective as of June 23, 1993. One of these leases has been amended to provide for incremental extensions of this lease term of up to an additional 12 years by drilling and completing additional wells on each lease prior to June 2003. In December of 2000 the Company added to its Tribal base inventory around the Pavillion Field by signing eleven additional ten-year leases covering nearly 25,800 net acres. The Company is currently awaiting final approval of the leases by the Bureau of Indian Affairs and has deferred drilling initially planned for early 2003 until the agreement between the Tribes and the Company on a methodology for payment of Tribal gas royalties is approved and executed by the Tribal Council and the Minerals Management Service.

REGULATION CANADA

Regulation of Gas and Oil Production and Price Controls

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size.

In Canada, oil and gas exports are subject to regulation by the National Energy Board (NEB), an independent federal regulatory agency. The Company does not, at present, export oil or gas under the terms of these regulations, but may be affected if regulations imposed by the NEB act to restrict the sales of gas and oil by other companies. Exports are also subject to the North American Free Trade Agreement (NAFTA) which became effective on January 1, 1994. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36-month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements. NAFTA contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

The provincial government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime on Crown lands is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross

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production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada and Alberta have established incentive programs which have included royalty rate deductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. At present, few of these programs are currently in effect.

In Alberta, certain producers of oil or natural gas are currently entitled to a credit against the royalties to the Crown by virtue of the ARTC (Alberta royalty tax credit) program. The credit is determined by applying a specified rate to a maximum of \$2 million CDN of Alberta Crown royalties payable for each producer or associated group of producers. The specified rate is a function of the Royalty Tax Credit reference price (RTCRP) which is set quarterly by the Alberta Department of Energy and ranges from 25% to 75%, depending on oil and gas par prices for the previous calendar quarter. The provincial government of Alberta has proposed changes to the ARTC program which have not been finalized.

Environmental Regulation

In Canada, the oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. The Company operates within this regulatory framework and continues to monitor and evaluate the impact of the regulatory regime when determining parameters for engaging in gas and oil activities and investments in Canada. In addition, the Company routinely obtains permits for its facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of the Company's facilities or operations.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition, AEPEA also imposes certain environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes penalties for violations. The Company has not received any violation notices under the AEPEA or from any Canadian environmental regulatory agency. The Company believes that it is in substantial compliance with current applicable Canadian environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on the Company's results of operations or financial condition.

FORWARD-LOOKING STATEMENTS

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical or present facts, that address activities, events, outcomes and other matters that the Company plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K.

Forward-looking statements may appear in a number of places and include statements with respect to, among other things:

any expected results or benefits associated with the Company's acquisitions;

estimates of the Company's future natural gas, crude oil and natural gas liquids production, including estimates of any increases in production;

planned capital expenditures and the availability of capital resources to fund capital expenditures;

estimates of the Company's gas and oil reserves;

the impact of U.S. and Canadian political and regulatory developments;

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the Company's future financial condition or results of operations and future revenues and expenses; and

the Company's business strategy and other plans and objectives for future operations.

Forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond the Company's control, incident to the exploration for and acquisition, development, production, marketing and sale of natural gas, natural gas liquids and crude oil in North America. These risks include, but are not limited to, commodity price volatility, third party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in this Form 10-K.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. The Company specifically disclaims all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaims any resulting liability for potentially related damages.

All forward-looking statements attributable to the Company are expressly qualified in their entirety by this cautionary statement.

RISK FACTORS

The Company's business is subject to a number of risks including, but not limited to, those described below:

Natural gas and oil price declines and volatility could adversely affect the Company's revenues, cash flows and profitability.

The Company's revenues, profitability and future rate of growth depend substantially upon the market prices of natural gas and oil, which fluctuate widely. Sustained declines in gas and oil prices may adversely affect the Company's financial condition, liquidity and results of operations. Factors that can cause market prices of natural gas and oil to fluctuate include:

relatively minor changes in the supply of and demand for natural gas and oil;

market uncertainty;

the level of consumer product demands;

weather conditions;

U.S. and foreign governmental regulations;

the price and availability of alternative fuels;

political and economic conditions in oil producing countries, particularly those in the Middle East;

the foreign supply of natural gas and oil;

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the price of gas and oil imports; and

overall U.S. and foreign economic conditions.

The Company cannot predict future natural gas and oil prices. At various times, excess domestic and imported supplies have depressed gas and oil prices. Lower prices may reduce the amount of natural gas and oil that the Company can produce economically and may also require the Company to write down the carrying value of its gas and oil properties. Substantially all of the Company's natural gas and oil sales are made in the spot market or pursuant to contracts based on spot market prices, not long-term fixed price contracts.

In an attempt to reduce price risk, the Company periodically enters into hedging transactions with respect to a portion of its expected future production. Such transactions may not reduce the risk or minimize the effect of any decline in natural gas or oil prices. Any substantial or extended decline in the prices of or demand for natural gas or oil would have a material adverse effect on the Company's financial condition and results of operations.

If natural gas and oil prices decrease or exploration efforts are unsuccessful, the Company may be required to take writedowns.

There is a risk that the Company will be required to write down the carrying value of its gas and oil properties, which would reduce the Company's earnings and stockholders' equity. A writedown could occur when gas and oil prices are low or if the Company has substantial downward adjustments to its estimated proved reserves, increases in its estimates of development costs or deterioration in its exploration results.

The Company accounts for its natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Gas and oil lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The capitalized costs of the Company's gas and oil properties may not exceed the estimated future net cash flows from its properties. If capitalized costs exceed future net revenues, the Company must write down the costs of the properties to the Company's estimate of fair market value. Any such charge will not affect the Company's cash flow from operating activities, but it will reduce the Company's earnings and stockholders' equity.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of gas and oil leasehold acquisition costs requires judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The Company reviews its gas and oil properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. Once incurred, a writedown of gas and oil properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require the Company to record an impairment of the recorded book values associated with gas and oil properties. In 1998, the Company recognized a pre-tax impairment of \$51.3 million, primarily as a result of the low market prices in effect at that time; similar impairments may be required in the future.

The marketability of the Company's production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities.

The marketability of the Company's production depends upon the availability, operation and capacity of gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. United States federal, state and foreign regulation of gas and oil production and transportation, general economic conditions and changes in supply and demand could adversely affect the Company's ability to produce and market natural gas and oil. If market factors changed dramatically, the financial impact on the Company could be substantial. The availability of markets and the volatility of product prices are beyond the Company's control and represent a significant risk.

The Company may not receive payment for a portion of its future production.

The Company's revenues are derived principally from uncollateralized sales to customers in the gas and oil industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in

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economic and other conditions. The publicly disclosed deteriorating financial conditions and recently reduced credit ratings of certain purchasers of production increase the possibility that the Company may not receive payment for a portion of its future production. In 2002, a previous purchaser of the Company's natural gas liquids in the Paradox Basin of Colorado and Utah defaulted on payments owed the Company totaling \$6.2 million; to date, the Company has received only a \$1.4 million cash settlement in connection with this default. The Company has attempted to obtain credit protections such as letters of credit, guarantees and prepayments from certain of its purchasers. The Company is unable to predict, however, what impact the financial difficulties of certain purchasers may have on its future results of operations and liquidity.

Estimates of gas and oil reserves are uncertain and inherently imprecise.

This Form 10-K contains estimates of the Company's proved gas and oil reserves and the estimated future net revenues from such reserves. Actual results will likely vary from amounts estimated and any significant variance could have a material adverse effect on the Company's future results of operations.

Gas and oil reserve estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable gas and oil reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document and the information incorporated by reference. The Company's properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing gas and oil prices and other factors, many of which are beyond its control.

At December 31, 2002, approximately 26% of the Company's U.S. estimated proved reserves were proved undeveloped, while 8% of the Company's Canadian estimated proved reserves were proved undeveloped. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimation of these non-producing categories is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved non-producing reserves will not be realized until some time in the future. The reserve data assumes that the Company will make significant capital expenditures to develop its reserves. Although the Company has prepared estimates of its gas and oil reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not be as estimated.

You should not assume that the estimated present value of future net cash flow referred to in this Form 10-K is the current fair value of the Company's estimated gas and oil reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for the Company.

The Company may not be able to obtain adequate financing to execute its operating strategy.

The Company has historically addressed its short and long-term liquidity needs through the use of cash flow provided by operating activities, the use of bank credit facilities and the issuance of equity securities. Without adequate financing, the Company may not be able to successfully execute its operating strategy. The Company continues to examine the following alternative sources of capital:

bank borrowings or the issuance of debt securities;

the issuance of common stock, preferred stock or other equity securities; and

joint venture financing.

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The availability of these sources of capital will depend upon a number of factors, some of which are beyond the Company's control. These factors include general economic and financial market conditions, natural gas and oil prices and the Company's market value and operating performance. The Company may be unable to execute its operating strategy if it cannot obtain adequate capital.

The Company may not be able to fund its planned capital expenditures.

The Company spends and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of gas and oil reserves. If low natural gas and oil prices, operating difficulties or other factors, many of which are beyond the Company's control, cause its revenues and cash flows from operating activities to decrease, the Company may be limited in its ability to spend the capital necessary to complete its capital expenditures program. In addition, if the Company's borrowing base under its credit facility is re-determined to a lower amount, this could adversely affect the Company's ability to fund its planned capital expenditures. The Company's capital expenditures, including acquisitions, were \$161.7 million during 2002, \$358.1 million during 2001 and \$150.5 million during 2000. The Company anticipates capital and exploration expenditures between \$155 and \$185 million in 2003, approximately 90% of which will be allocated to exploration and development activity. After utilizing its available sources of financing, the Company may be forced to raise additional equity or debt proceeds to fund such expenditures. Additional equity or debt financing or cash flow provided by operations may not be available to meet the Company's capital expenditures requirements.

The Company may not be able to replace production with new reserves.

The Company's reserves will decline as they are produced unless the Company acquires properties with proved reserves or conducts successful development and exploration drilling activities. The Company's future natural gas and oil production is highly dependent upon its level of success in finding or acquiring additional reserves, which it may not be successful in doing.

The successful acquisition of producing properties requires an assessment of a number of factors, many of which are beyond the Company's control. These factors include recoverable reserves, future gas and oil prices, operating costs and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, the Company performs a review of the subject properties, which it believes is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, the review will not permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. The Company may not be able to acquire properties at acceptable prices because the competition for producing gas and oil properties is intense and many of the Company's competitors have financial and other resources that are substantially greater than those available to the Company.

The Company's operations are subject to numerous risks of gas and oil drilling and production activities.

Gas and oil drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be found. Gas and oil drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond the Company's control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of natural gas and oil also affect the cost of and the demand for drilling rigs, production equipment and related services.

New wells that the Company drills may not be productive and the Company may not recover all or any portion of its investment. The cost of drilling and completing wells is often uncertain. Drilling for natural gas and oil may be unprofitable. Drilling activities can result in dry wells

and wells that are productive but do not produce sufficient net revenues after operating and other costs to recoup drilling costs.

The Company's industry experiences numerous operating risks.

The exploration, development and operation of gas and oil properties involves a variety of operating risks including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards, including oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry-operating risks occur, the Company could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations.

The Company maintains insurance against some, but not all, of the risks described above. Such insurance may not be adequate to cover losses or liabilities. Also, the Company cannot predict the continued availability of insurance at premium levels that justify its purchase. The terrorist attacks on September 11, 2001 and the changes in the insurance markets attributable to those attacks may make some types of insurance more difficult to obtain. The Company may be unable to secure the level and types of insurance it would otherwise have secured prior to September 11th. The Company may not be able to maintain insurance in the future at rates it considers reasonable. The occurrence of a significant event, not fully insured or indemnified against, could materially and adversely affect the Company's financial condition and operations.

Terrorist attacks aimed at the Company's facilities could adversely affect its business.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11th attacks, the U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected the Company's operations to increased risks. Any future terrorist attack at the Company's facilities, or those of its purchasers, could have a material adverse effect on the Company's business.

The covenants in the agreements governing the Company's debt could negatively impact the Company's financial condition, results of operations and business prospects.

The terms of the agreements governing the Company's debt impose significant restrictions on the Company's ability and the ability of its subsidiaries to take a number of actions that the Company may otherwise desire to take, thereby negatively impacting the Company's financial condition, results of operations and business prospects. These provisions restrict:

the incurrence of additional debt;

the payment of dividends on stock, redemption of stock or redemption of subordinated debt;

the making of investments;

the creation of liens on the Company's assets;

the sale of assets;

the guaranteeing of other indebtedness;

the entering into agreements that restrict dividends from the Company's subsidiaries to the Company;

the merger, consolidation or transfer of all or substantially all of the Company's assets; and

the entering into transactions with affiliates.

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The Company's level of indebtedness, and the covenants contained in the agreements governing the Company's debt, could have important consequences on its operations, including, for example, making the Company vulnerable to increases in interest rates, because debt under the Company's credit facility will be at variable rates.

The Company may be required to repay all or a portion of its debt on an accelerated basis in certain circumstances. If the Company fails to comply with the covenants and other restrictions in the agreements governing its debt, it could lead to an event of default and the acceleration of the Company's repayment of outstanding debt. The Company's ability to comply with these covenants and other restrictions may be affected by events beyond the Company's control, including prevailing economic and financial conditions. The credit facility allows the lenders one scheduled redetermination of the borrowing base each December. In addition, the lenders may elect to require one unscheduled redetermination in the event the borrowing base utilization exceeds 50% of the borrowing base at any time for a period of 15 consecutive business days. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, the Company could be forced to repay a portion of its bank debt.

The Company may not have sufficient funds to make such repayments. If the Company is unable to repay its debt out of cash on hand, it could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. The Company may not be able to generate sufficient cash flow from operating activities to pay the interest on its debt. In addition, future borrowings, equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of the Company's debt, including its credit facility, may also prohibit the Company from taking such actions. Factors that will affect the Company's ability to raise cash through an offering of its capital stock, a refinancing of its debt or a sale of assets include financial market conditions and the Company's market value and operating performance at the time of such offering or other financing. The Company may not successfully complete any such offering, refinancing or sale of assets.

Competition within the Company's industry may adversely affect its operations.

Competition in the Wind River and Green River Basins of Wyoming, the Piceance Basin of Colorado and the Paradox Basin of Utah and Colorado is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. The Company competes with major gas and oil companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of the Company's competitors have financial resources and exploration and development budgets that are substantially greater than the Company's, which may adversely affect the Company's ability to compete.

The Company may incur substantial costs to comply with the various U.S. federal, state and local environmental laws and regulations that affect its gas and oil operations.

The Company's gas and oil operations are subject to stringent U.S. federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the incurrence of investigatory or remedial obligations, or the imposition of injunctive relief.

The environmental laws and regulations to which the Company is subject may:

require the acquisition of a permit before drilling commences;

restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

impose substantial liabilities for pollution resulting from Company operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Company to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on the earnings, results of operations, competitive position or financial condition of the Company. Over the years, the Company has owned or leased numerous properties for gas and oil activities upon which petroleum hydrocarbons or other materials may have been released by the Company or by predecessor property owners or lessees who were not under the Company's control.

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Under applicable environmental laws and regulations, including CERCLA, RCRA and analogous state laws, the Company could be held strictly liable for the removal or remediation of previously released materials or property contamination at such locations regardless of whether the Company was responsible for the release or if the Company's operations were standard in the industry at the time they were performed. For additional information about the specific environmental laws and regulations to which the Company is subject, see " Regulation United States Environmental Regulation."

The loss of key personnel could adversely affect the Company's ability to operate.

The Company's operations are dependent upon a relatively small group of key management and technical personnel. The unexpected loss of the services of one or more of these individuals could have an adverse effect on the Company. The Company considers all of its executive officers to be key employees. Such individuals may not remain with the Company for the immediate or foreseeable future. The Company does not maintain key man insurance on any employee, and has an employment contract only with James D. Lightner, the Company's Chairman, Chief Executive Officer and President.

Hedging transactions may limit the Company's potential gains.

In order to manage its exposure to price risks in the marketing of gas and oil, the Company periodically enters into gas and oil price hedging arrangements, such as commodity swap agreements, forward sale contracts, commodity futures, options and similar agreements, with respect to a portion of its expected production. While intended to reduce the effects of volatile gas and oil prices, such transactions, depending on the hedging instrument used, may limit the Company's potential gains if gas and oil prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose the Company to the risk of financial loss in certain circumstances, including instances in which:

production is substantially less than expected;

the counterparties to the Company's futures contracts fail to perform the contracts; or

a sudden, unexpected event materially impacts gas or oil prices.

The Company does not pay dividends.

The Company has never declared or paid any cash dividends on its common stock and has no intention to do so in the near future. The restrictions on the Company's present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law. In addition, the Company has entered into a credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

The Company's Certificate of Incorporation and rights plan have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of the Company's Certificate of Incorporation and stockholders' rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with the Company's board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions could have the effect of preventing stockholders from realizing a premium on their investment.

The Company's Certificate of Incorporation authorizes the Company's board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and the availability of authorized but unissued common stock. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

In 1991, the Company adopted a rights plan, pursuant to which uncertificated stock purchase rights were distributed to stockholders at a rate of one right for each share of common stock held of record as of March 15, 1991. On March 1, 2001, the Company amended and restated the rights plan. Each right entitles the registered holder to purchase, for a \$120 per share exercise price, shares of common stock or other securities of the Company (or, under certain circumstances, of the acquiring person) worth twice the per share exercise price of the right. The rights plan is designed to enhance the Company's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire the Company by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by the Company's board, including a takeover that may be