EVERGREEN RESOURCES INC
Form 10-K405
March 11, 2002

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For The Fiscal Year Ended December 31, 2001

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 0-13171

EVERGREEN RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Colorado	**84-0834147**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1401 17th Street **Suite 1200** **Denver, Colorado**	**80202**
(Address of principal executive offices)	(Zip Code)

(303) 298-8100

(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	New York Stock Exchange
Share Purchase Rights	New York Stock Exchange

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

None

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

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. ý

As of February 28, 2002, the Registrant had 18,850,336 common shares outstanding, and the aggregate market value of the common shares held by non-affiliates was approximately $737.5 million based upon the closing price of $41.80 per share for the common stock on February 28, 2002, as reported on the New York Stock Exchange.

DOCUMENTS INCORPORATED BY REFERENCE: DEFINITIVE PROXY MATERIALS FOR 2002 ANNUAL MEETING OF STOCKHOLDERS PART III, ITEMS 10, 11, 12, AND 13.

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CERTAIN DEFINITIONS

The following are definitions of terms commonly used in the oil and natural gas industry and this document.

Unless otherwise indicated in this document, natural gas volumes are stated at the legal pressure base of the state or area in which the reserves are located at 60 (degrees) Fahrenheit. As used in this document, the following terms have the following specific meanings: "Mcf" means thousand cubic feet, "MMcf" means million cubic feet, "Bcf" means billion cubic feet and "MMBtu" means million British thermal units.

Average finding cost. The amount of total capital expenditures, including acquisition costs, and exploration and abandonment costs, for oil and natural gas activities divided by the amount of proved reserves added in the specified period.

Capital expenditures. Costs associated with exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land related overhead expenditures; delay rentals; producing property acquisitions; other miscellaneous capital expenditures; compression equipment and pipeline costs.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a producing horizon known to be productive.

Exploratory well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Gob gas. Gob gas is methane that has collected in abandoned underground coal mines.

Gross acres or gross wells. The total acres or wells, as the case may be, in which the Company has a working interest.

LOE. Lease operating expenses, which includes all costs related to production activities. Direct costs such as direct labor, direct materials, certain workover costs, repairs and maintenance, insurance costs, gas collection costs.

Mine gas interaction well. A well drilled into the fractured area surrounding an abandoned coal mine.

Net acres or net wells. A net acre or well is deemed to exist when the sum of the Company's fractional ownership working interests in gross acres or wells, as the case may be, equals one. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

Operator. The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

Present value of future net revenues or PV-10. The present value of estimated future net revenues to be generated from the production of proved reserves, net of estimated production and ad valorem taxes, future capital costs and operating expenses, using prices and costs in effect as of the date indicated, without giving effect to federal income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." The present value reflects the

effect of time on the present value of the revenue stream. PV-10 should not be construed as being the fair market value of the properties.

Recompletion. The completion of an existing well for production from a formation that exists behind the casing of the well.

Reserves. Natural gas and crude oil, condensate and natural gas liquids on a net revenue interest basis, found to be commercially recoverable. "Proved developed reserves" includes proved developed producing reserves and proved developed behind-pipe reserves. "Proved developed producing reserves" includes only those reserves expected to be recovered from existing completion intervals in existing wells. "Proved undeveloped reserves" include those reserves expected to be recovered from new wells on proved undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Undeveloped acreage. Lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether or not such acreage contains proved reserves.

Working interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill and produce oil and natural gas on the leased acreage and requires the owner to pay his/her proportionate share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to governmental tax receipts and mineral interest royalties.

PART I

ITEM 1. BUSINESS

General

Evergreen Resources, Inc. ("Evergreen" or "the Company") is a Colorado corporation organized on January 14, 1981. Evergreen is an independent energy company engaged in the operation, development, production, exploration and acquisition of natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Its current operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado. The Company has begun coal bed methane projects in the United Kingdom and Alaska. In addition, the Company is engaged in the exploration of natural gas prospects in Northern Ireland and the Republic of Ireland, and owns additional interests in other domestic and international areas.

Evergreen maintains its principal executive offices at 1401 17th Street, Suite 1200, Denver, Colorado 80202; telephone (303) 298-8100.

The authorized capitalization of the Company is 50,000,000 shares of no par value common stock, of which 18,847,178 shares were issued and outstanding at December 31, 2001, and 24,900,000 shares of $1.00 par value preferred stock, none of which were issued and outstanding at December 31, 2001.

This report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including statements regarding, among other items, (i) the Company's growth strategies, (ii) anticipated trends in the Company's business and its future results of operations, (iii) market conditions in the oil and gas industry, (iv) the ability of the Company to make and integrate acquisitions and (v) the outcome of litigation and the impact of governmental regulation. These forward-looking statements are based largely on the Company's expectations and are subject to a number of risks and uncertainties, many of which are beyond the Company's control. Actual results could differ materially from those implied by these forward-looking statements as a result of, among other things, a decline in natural gas production, a decline in natural gas prices, incorrect estimations of required capital expenditures, increases in the cost of drilling, completion and gas collection, an increase in the cost of production and operations, an inability to meet growth projections, or changes in general economic conditions. These and other risks are discussed under the heading "Business Certain Risks." In light of these and other risks and uncertainties of which the Company may be unaware or which the Company currently deems immaterial, there can be no assurance that actual results will be as projected in the forward-looking statements.

For a discussion of the development of the Company's business, see Item 2 and for a discussion of the assets by geographic area, see Note 15 to the Consolidated Financial Statements.

Business Activities

Raton Basin

The Company's current operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado.

The Company is one of the largest holders of oil and gas leases in the Raton Basin. Evergreen holds interests in approximately 274,000 gross acres of coal bed methane properties in the basin. At December 31, 2001, the Company had estimated net proved reserves of 1.05 Tcf, 65% of which were proved developed, with a PV-10 of approximately $598 million. The Company's net daily gas sales at December 31, 2001 were approximately 97 MMcf from a total of 681 net producing wells. Total

production from the Company's wells accounted for an estimated 76% of the gas sold from the Raton Basin at December 31, 2001. Evergreen's Raton Basin drilling program has enabled the Company to build an extensive inventory of additional drilling locations. The Company has identified at least 750 additional drilling locations on its Raton Basin acreage, of which 329 were included in its estimated proved reserve base at December 31, 2001. The Company operates and has a 100% working interest in substantially all of its Raton Basin acreage and wells.

Since Evergreen began its drilling efforts in the Raton Basin, the Company has drilled more than 500 wells and achieved a success rate of approximately 98%. In addition, the Company has acquired over 200 producing wells in the Raton Basin since the beginning of the Raton Basin project. From March 31, 1995 through December 31, 2001, Evergreen grew its estimated proved reserves from 58 Bcf to 1,051 Bcf, which represents a compound annual growth rate in excess of 50%. During the same period, the Company's net daily gas sales increased from just over 1 MMcf to approximately 97 MMcf.

Management believes the Company's success in the Raton Basin has enabled Evergreen to become one of the lowest-cost finders, developers and producers among U.S. publicly-traded independent oil and gas companies. From the beginning of the Company's Raton Basin project through December 31, 2001, the Company has spent approximately $240 million on the drilling and completion of its wells, pipelines, gas collection systems and compression equipment, and $244 million on the acquisition of additional properties. This represents an estimated total finding and development cost of $0.31 per Mcf excluding acquisitions and $0.45 per Mcf including acquisitions.

United Kingdom Project

Evergreen holds exploration licenses covering approximately 452,000 acres in the United Kingdom. In April 2000, the Company began drilling on these coal bed methane properties using the Company's own purpose-built equipment and personnel. Since the inception of the project, a total of eleven wells have been drilled in the U.K. Total costs through December 31, 2001 were approximately $23 million, which includes the cost of drilling and completion and other associated costs such as license fees. During 2001, Evergreen invested approximately $3.6 million in this project. In 2002, the Company anticipates an additional investment in the U.K. of up to approximately $5 million.

Northern Ireland and the Republic of Ireland Project

In March and April 2001, the Company acquired 100% working interest in 1,085,000 acres of prospective tight gas sand properties in Northern Ireland (605,000 acres) and in the Republic of Ireland (480,000 acres) for total consideration of $1,250,000 (23,200 shares of Evergreen common stock valued at $750,000 and $500,000 in cash) plus a small retained net profits interest. The Company drilled four wells in Northern Ireland and two wells in the Republic of Ireland during 2001 to depths ranging from approximately 2,700 feet to 4,400 feet. The Company expects its evaluation of this initial drilling program to be completed by mid-year 2002. During 2001, Evergreen invested approximately $7.3 million in these two projects, and the Company anticipates an additional investment in these projects of approximately $5 million in 2002.

Business Strategy

The Company's objective is to enhance shareholder value by increasing reserves, production, cash flow, earnings and net asset value per share. To accomplish this objective, the Company intends to capitalize on its experience and operating expertise in coal bed methane properties and on its other competitive strengths, which include:

- an extensive inventory of drilling locations;

- a track record for significantly growing the Company's reserve base through development drilling and acquisitions; and an industry leading position as a low-cost finder, developer and producer of natural gas.

Customers and Markets

Gas Marketing. Primero Gas Marketing Company ("Primero") is a wholly-owned subsidiary of the Company that was formed to market and sell natural gas for the Company and third parties. To date, Primero has marketed and sold gas only on behalf of the Company, royalty interest and working interest partners. Primero also operates the Company's gas collection systems and purchases all the Company's production from its Raton Basin wells.

Gas production from the Raton Basin is transported by Colorado Interstate Gas Co. ("CIG") through the Campo Lateral, a 115 mile, 16-inch pipeline and the Picketwire Lateral, which is a 10-inch and 20-inch looped line that connects to CIG's main pipeline system and permits Evergreen to sell its gas into the Mid-continent market.

Current Raton Basin gas sales total approximately 150 MMcf per day. Takeaway capacity on the CIG system from the Raton Basin is currently 232 MMcf per day. CIG is planning an additional 30 MMcf per day expansion in 2002, which will increase the takeaway capacity to 262 MMcf per day. The Company believes that this expansion will provide sufficient transportation capacity to accommodate significant growth in its gas sales volumes in the future.

The Company's current firm transportation commitments are 97 MMcf of gross gas sales per day. In addition, the Company has committed to an additional 30 MMcf per day, subject to a ramp-up schedule which anticipates 5 MMcf per day increments each four months from June 2002 through February 2004. Thus, Evergreen's total transportation commitments will increase in four increments to a total of 127 MMcf gross per day by February 2004. If the Company is unable to fulfill its transportation commitments, amounts paid for transportation on up to 41 MMcf per day can be credited toward future transportation costs through August 2006.

Major Customers. Evergreen has three major customers, Natural Gas Transmission Services, Inc., Xcel Energy and subsidiaries, and Aquila Energy Corporation, which purchased approximately 46%, 31% and 10%, respectively, of the Company's gas production for the year ended December 31, 2001. Based on the general demand for gas, the loss of any or all of these customers would not be expected to have a material adverse effect on Evergreen's business. As the Company's base of production grows in the Raton Basin, the Company hopes to be able to enter into long-term contracts with end users at favorable prices. Currently, the Company's gas is sold at spot market prices, under short-term contracts, and under swaps/ hedges.

Competition. The Company competes with numerous other companies in virtually all facets of its business, including many that have significantly greater resources. Such competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties than the financial or personnel resources of the Company permit. The ability of the Company to increase reserves in the future will be dependent on its ability to select and acquire suitable producing properties and prospects for future exploration and development. The availability of a market for oil and natural gas production depends upon numerous factors beyond the control of producers, including but not limited to the availability of other domestic or imported production, the locations and capacity of pipelines, and the effect of federal and state regulation on such production.

Government Regulation of the Oil and Gas Industry

Domestic

General. The Company's business is affected by numerous laws and regulations, including, among others, laws and regulations relating to energy, environment, conservation and tax. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on the Company's business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to the Company, the Company cannot predict the overall effect of such laws and regulations on its future operations.

The Company believes that its operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on the Company's method of operations than on other similar companies in the energy industry.

The following discussion contains summaries of certain laws and regulations and is qualified in its entirety by the foregoing.

Federal Regulation of the Sale and Transportation of Oil and Gas. Various aspects of the Company's oil and natural gas operations are regulated by agencies of the Federal government. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In the past, the Federal government has regulated the prices at which oil and gas could be sold. While "first sales" by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA in 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act (the "Decontrol Act"). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Commencing in April 1992, the FERC issued Orders Nos. 636, 636-A, 636-B, 636-C and 636-D ("Order No. 636"), which require interstate pipelines to provide transportation services separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open access transportation on a nondiscriminatory basis that is equal for all natural gas shippers. Although Order No. 636 does not directly regulate the Company's production activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. It is unclear what impact, if any, increased competition within the natural gas industry under Order No. 636 will have on the Company's activities.

The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In particular, the FERC is conducting a broad review of its transportation regulations, including how they operate in conjunction with state proposals for retail gas marketing restructuring, whether to eliminate cost-of-service rates for short-term transportation, whether to allocate all short-term capacity on the basis of competitive auctions, and whether changes to long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. In February 2000, the FERC issued Order No. 637 amending certain regulations governing interstate natural gas pipeline companies in response to the development of more competitive markets for natural gas and natural gas transportation. The goal of Order No. 637 is to "fine tune" the open access regulations implemented by Order No. 636 to accommodate subsequent changes in the market. Key provisions of Order No. 637 include: (1) waiving the price

ceiling for short-term capacity release transactions until September 30, 2002, subject to review and possible extension of the program at that time; (2) permitting value-oriented peak/off peak rates to better allocate revenue responsibility between short-term and long-term markets; (3) permitting term-differentiated rates, in order to better allocate risks between shippers and the pipeline; (4) revising the regulations related to scheduling procedures, capacity, segmentation, imbalance management, and penalties; (5) retaining the right of first refusal ("ROFR") and the five-year matching cap for long-term shippers at maximum rates, but significantly narrowing the ROFR for customers that the FERC does not deem to be captive; and (6) adopting new web site reporting requirements that include daily transactional data on all firm and interruptible contracts and daily reporting of scheduled quantities at points or segments. The new reporting requirements became effective September 1, 2000. The Company cannot predict what action the FERC will take on these matters, in the future, nor can it accurately predict whether the FERC's actions will, over the long term, achieve the goal of increasing competition in markets in which the Company's natural gas is sold. However, the Company does not believe that it will be affected by any FERC-related action in a materially different manner than other natural gas producers and marketers with which it competes.

Commencing in October 1993, the FERC issued a series of rules (Order Nos. 561 and 561-A) establishing an indexing system under which oil pipelines will be able to change their transportation rates, subject to prescribed ceiling levels. The indexing system, which allows pipelines to make rate changes to track changes in the Producer Price Index for Finished Goods, minus one percent, became effective January 1, 1995. The Company does not believe that, if it were to produce crude oil, these rules affect it any differently than other oil producers and marketers with which it competes.

The FERC has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided thereon, then such facilities and services may be subject to regulation by state authorities in accordance with state law. A number of states have either enacted new laws or are considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. The Company's gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although the Company does not believe that it would be affected by such regulation any differently than other natural gas producers or gatherers. In addition, the FERC's approval of transfers of previously regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to FERC regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

The Company owns certain natural gas pipeline facilities that it believes meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction. Whether on state or federal land, natural gas gathering may receive greater regulatory scrutiny in the post-Order No. 636 environment.

The Company conducts certain operations on federal oil and gas leases, which are administered by the Minerals Management Service (the "MMS"). Federal leases contain relatively standard terms and require compliance with detailed MMS regulations and orders, which are subject to change. Among other restrictions, the MMS has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Under certain circumstances, the MMS may require any Company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's financial condition, cash flows and operations. The MMS issued a final

rule that amended its regulations governing the valuation of crude oil produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil produced from federal leases. The lawfulness of the new rule has been challenged in federal court. Evergreen cannot predict whether this new rule will be upheld in federal court, nor can the Company predict whether the MMS will take further action on this matter. However, the Company does not believe that, if it were to produce crude oil, this new rule will affect it any differently than other producers and marketers of crude oil.

Additional proposals and proceedings that might affect the oil and gas industry are pending before Congress, the FERC, the MMS, state commissions and the courts. The Company cannot predict when or whether any such proposals and proceedings may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, the Company does not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon the capital expenditures, earnings or competitive position of the Company or its subsidiaries. No material portion of Evergreen's business is subject to re-negotiation of profits or termination of contracts or subcontracts at the election of the Federal government.

Bureau of Land Management. Of the Company's Raton Basin acreage, approximately 134,000 gross acres are held within three federal units that the Company operates and that are administered by the Federal Bureau of Land Management ("BLM"). See "Item 2. Properties Raton Basin Properties and Operations." Inclusion of property within a unit simplifies lease maintenance for the Company and promotes orderly development of its coal bed methane project.

The BLM controls isolated parcels of federally owned surface and/or minerals in the Raton Basin. To date, two coal bed methane wells have been drilled on BLM minerals. Drilling and development of federal minerals and construction activities on federal surface are subject to the National Environmental Policy Act ("NEPA"). BLM has delayed additional drilling on federal oil and gas leases held by Evergreen, pending completion of an environmental assessment under NEPA. Development of adjacent fee lands and minerals has proceeded unhindered. Access to fee lands has not been hindered by the presence of isolated parcels of federal surface. The number of proposed wells on BLM minerals represents approximately one percent of the total number of wells Evergreen has planned in the Raton Basin.

State Regulation. The Company's operations are also subject to regulation at the state level and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used and produced in connection with operations. The Company's operations are also subject to various conservation laws and regulations. These include (1) the size of drilling and spacing units or proration units, (2) the density of wells that may be drilled and (3) the unitization or pooling of 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 ratability of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but (except as noted above) does not generally entail rate regulation. These regulatory burdens may affect profitability, and the Company is unable to predict the future cost or impact of complying with such regulations.

Environmental Matters. The Company is subject to extensive federal, state and local environmental laws and regulations that, among other things, regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and in some cases injunctive relief for failure to comply. Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination. Such laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws, rules and regulations may require the rate of oil and natural gas production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Legislation has been proposed and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes." This reclassification would make such wastes subject to much more stringent and expensive storage, treatment, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant adverse impact on the operating costs of the Company, as well as the oil and gas industry in general. Initiatives to regulate further the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at county, municipal and local government levels. These various initiatives could have a similar adverse impact on the Company. The regulatory burden on the oil and natural gas industry increases its cost and risk of doing business and consequently affects its profitability.

Compliance with these environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect upon the Company's capital expenditures, earnings or competitive position. The Company believes that it is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on it. Nevertheless, changes in environmental laws and regulations have the potential to affect adversely Evergreen's operations. For example, the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault (i.e. strict and joint and several liability) or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state government to pursue such claims. It is also not uncommon for neighboring landowners and other third parties to file claims for personal injury or property or natural resource damages allegedly caused by the hazardous substances released into the environment. Under CERCLA, certain oil and gas materials and products are, by definition, excluded from the term "hazardous substances." At least two Federal courts have held that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA. Similarly, under the federal Resource, Conservation and Recovery Act of 1976, as amended ("RCRA"), which governs the generation, treatment, storage and disposal of "solid wastes" and "hazardous wastes," certain exploration and production wastes are exempt from the definition of "hazardous wastes." This exemption continues to be subject to judicial interpretation and increasingly stringent state interpretation. During the normal course of the Company's operations, the Company generates or has generated in the past exempt and non-exempt wastes, including hazardous wastes, that are subject to RCRA and comparable state statutes and implementing regulations. The federal Environmental Protection Agency ("EPA") and various state agencies continue to promulgate

regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

The Company currently owns or leases, and has in the past owned or leased, several properties that have long been used to store and maintain oil and gas exploration and production equipment. In particular, current and prior operations of the Company included oil and gas production in the Rocky Mountain states and the portion of the Permian Basin that lies within the State of New Mexico. Although the Company utilized operating and disposal practices that were standard for the industry at the time, hydrocarbons, materials and/or solid or hazardous wastes may in the past 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 or placed for disposal. In addition, many of these properties have from time to time been operated by third parties whose management of hydrocarbons, hazardous materials and/or solid or hazardous and wastes was not under the Company's control. These properties and the hydrocarbons, materials or wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws and regulations. Under such laws and regulations, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination).

In connection with the Company's coal bed methane gas production, the Company from time to time conducts production enhancement techniques, including various activities designed to induce hydraulic fracturing of the coal bed. While the Company performs its production enhancement techniques in substantial compliance with the requirements set forth by the State of Colorado, neither Colorado nor EPA regulates this coal bed formation hydraulic fracturing as a form of underground injection. On August 7, 1997, the U.S. Court of Appeals for the Eleventh

Circuit held, in a case brought by a citizen environmental organization, that hydraulic fracturing performed in coal bed methane gas production in Alabama falls within the definition of "underground injection" as defined in the federal Safe Drinking Water Act and, therefore, EPA is required to regulate this activity. As a consequence of this holding, the Eleventh Circuit also granted a petition filed by the plaintiff in the case to review EPA's refusal to initiate proceedings that would withdraw federal approval of Alabama's Underground Injection Control program. EPA has recently commenced a comprehensive study of environmental risks associated with coal bed methane hydraulic fracturing techniques and anticipates that its final report will be completed by winter 2002. It is possible that hydraulic fracturing of coal beds for methane gas production will become regulated within the United States as a form of underground injection, resulting in the imposition of stricter performance standards (which, if not met, could result in diminished opportunities for methane gas production enhancement) and increased administrative and operating costs for the Company. Evergreen's management cannot predict whether potential future regulation of hydraulic fracturing as a form of underground injection would have an adverse material effect on the Company's operations or financial position. However, such regulation is not expected to be any more burdensome to the Company than it would be to other similarly situated companies involved in coal bed methane gas production or tight gas sands production within the United States.

In Evergreen's coal bed methane gas production, the Company typically brings naturally occurring groundwater to the surface as a by-product of the production of methane gas. This "produced water" is either re-injected into the subsurface or stored or disposed of in evaporation ponds or permitted natural collection features located on the surface at or near the well-site in compliance with federal and state statutes and regulations. In some cases, the produced water is used for stock watering, agricultural or dust suppression purposes, also in substantial compliance with federal, state and local laws and regulations. The legal and regulatory classification of this produced water under the environmental laws discussed above as well as under the federal Clean Water Act, a strict liability statute that governs the discharge of "pollutants" to "waters of the United States," has been a source of dispute, as discussed

below. Under the Clean Water Act and various other state requirements and regulations, EPA, the State of Colorado's Department of Public Health and the Environment ("CDPHE"), and the Colorado Oil and Gas Conservation Commission ("COGCC") each continue to assert administrative and regulatory enforcement authority over the storage and disposal of such produced water. The EPA and the CDPHE have recently clarified their classification of either: (1) produced water as a "pollutant," and (2) the storage, use and disposal of such water on the surface as a "discharge to waters of the United States." This regulatory determination could have a significant impact on the regulatory treatment of this groundwater management practice and on the Company's understanding of its past and future compliance in connection with the Clean Water Act. On January 7, 2000, Evergreen Operating Corporation ("EOC"), one of the Company's wholly-owned subsidiaries, agreed to a Compliance Order on Consent from the CDPHE that resolved certain water storage and discharge issues between the CDPHE and EOC. Under the Consent Order, EOC has obtained additional permits and has installed a water supply system as a Supplemental Environmental Project ("SEP"), in lieu of civil penalties of $173,000, that will benefit rural landowners in one of the areas in which the Company operates. The Company may process a portion of its produced water to meet potability standards or pursue other water supply project options in cooperation with local governments. Under the Consent Order, the minimum and maximum costs of the SEP are $347,440 and $367,000, respectively. The Consent Order resolves all outstanding issues between EOC and Colorado state regulatory agencies, particularly the CDPHE, governing the discharge of produced water from the Company's coal bed methane operations in the Raton Basin.

The Company's operations involve the use of gas-fired compressors to transport collected gas; these compressors are subject to federal and state regulations for the control of air emissions. The Company has filed a Title V permit application for its Burro Canyon compressor facility and construction permits for natural gas-fired compressors at other facilities, as applicable. Title V status for a facility results in significant increased testing, monitoring and administrative and compliance costs. To date, other compressor facilities have not triggered Title V requirements due to their design and the use of state-of-the-art engines and pollution control equipment that serve to reduce air emissions. In the autumn of 2000, Evergreen made a capital investment in enhanced emissions control equipment for six of its compressors at the Rita Canyon compressor facility, which eliminated this facility from the Title V threshold. The Company has obtained construction permits for additional compression in excess of current needs in anticipation of increased production from the Raton Basin. However, in the future, additional facilities could become subject to Title V requirements as compressor facilities are expanded or if regulatory interpretations of Title V applicability change. Stack testing and emissions monitoring costs will likely increase as these facilities are expanded, and if Title V compliance issues will need to be resolved. Evergreen recently received a Compliance Order on Consent resolving the CDPHE Air Pollution Control Division's allegations that the Company violated certain air permitting requirements. As settlement of these claims, the Company has paid a $52,000 civil penalty and performed an SEP, including the installation of pollution control equipment, at a combined cost of approximately $100,000. Evergreen is also engaged in discussions with CDPHE Air Pollution Control Division over the nature of a state permit requirement to report "insignificant sources" of emissions at the Burro Canyon facility. Evergreen believes that it is in substantial compliance with applicable laws, rules and regulations relating to the control of air emissions at all of its facilities. The Company is exploring the possibility of favorable tax treatment from the State of Colorado for the installation of oxidizing catalysts to reduce carbon monoxide emissions from the Company's compressor facilities and recovery of some compliance costs from the compressor engine manufacturer.

At this time, the Company has no plans to make any material capital expenditures for environmental control facilities.

Although the Company maintains insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no

assurance that such insurance will be adequate to cover all such costs, that such insurance will continue to be available in the future or that such insurance will be available at premium levels that justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on the Company's financial condition and operations.

International

The Company's oil and gas operations outside of the United States are subject to similar foreign governmental controls and restrictions pertaining to the environment. These regulations, controls and restrictions may be more complex and onerous, resulting in increased costs for regulatory compliance over similar operations in the U.S. These costs may be increased by foreign government's unfamiliarity with coal bed methane operations and onshore drilling practices that are standard in the United States. The Company believes that compliance with existing requirements of such governmental bodies has not had a material adverse effect on the Company's operations.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time the Company acquires leases of properties believed to be suitable for drilling operations. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted by independent attorneys. Once production from a given well is established, the Company prepares a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. The Company believes that titles to its leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Employees

At February 15, 2002, the Company had 215 full-time employees.

Certain Risks

Oil and gas prices are volatile, and an extended decline in prices would hurt the Company's profitability and financial condition.

Evergreen's revenues, operating results, profitability, future rate of growth and the carrying value of its oil and gas properties depend heavily on prevailing market prices for oil and gas. Management of the Company expects the markets for oil and gas to continue to be volatile. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on the Company's financial condition and results of operations. It could reduce the Company's cash flow and borrowing capacity, as well as the value and the amount of its gas reserves. All of Evergreen's proved reserves are natural gas. Therefore, the Company is more directly impacted by volatility in the price of natural gas. Various factors beyond the Company's control will affect prices of oil and gas, including:

- worldwide and domestic supplies of oil and gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil or gas producing regions;
- the price and level of foreign imports;
- worldwide economic conditions;

marketability of production;

the level of consumer demand;

the price, availability and acceptance of alternative fuels;

the availability of pipeline capacity;

weather conditions; and

actions of federal, state, local and foreign authorities.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and gas.

The Company periodically reviews the carrying value of its oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission. Under these rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if the ceiling is exceeded, even if prices were depressed for only a short period of time. The Company may be required to write down or impair the carrying value of its oil and gas properties when oil and gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings, and book value but would not impact cash flow from operating activities. Once incurred, a write-down of oil and gas properties is not reversible at a later date.

The Company's operations require large amounts of capital.

Evergreen's current development plans will require it to make large capital expenditures for the exploration and development of its natural gas properties. Also, the Company must secure substantial capital to explore and develop its international projects. Historically, Evergreen has funded its capital expenditures through a combination of funds generated internally from sales of production or properties, the issuance of equity, long-term debt financing and short-term financing arrangements. Management cannot be sure that any additional financing will be available to the Company on acceptable terms. Future cash flows and the availability of financing will be subject to a number of variables, such as:

the success of its coal bed methane project in the Raton Basin,

the Company's success in locating and producing new reserves,

the level of production from existing wells, and

prices of oil and natural gas.

Issuing equity securities to satisfy the Company's financing requirements could cause substantial dilution to existing shareholders. Debt financing could lead to:

- a substantial portion of the Company's operating cash flow being dedicated to the payment of principal and interest,
- the Company being more vulnerable to competitive pressures and economic downturns, and
- restrictions on the Company's operations.

If the Company's revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if it could not obtain capital through its credit facility or otherwise, the Company's ability to execute its development plans, replace its reserves or maintain production levels could be greatly limited.

Information concerning the Company's reserves and future net revenue estimates is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond the control of the Company. Estimates of proved undeveloped reserves, which comprise a significant portion of the Company's reserves, are by their nature uncertain. The reserve data included in this Form 10-K are estimated. Although management believes they are reasonable, estimates of production, revenues and reserve expenditures will likely vary from actual, and these variances may be material.

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material. See "Item 2. Properties Natural Gas Reserves."

Analysts and investors should not construe PV-10 as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. Management has based the estimated discounted future net cash flows from proved reserves on prices and costs as of the date of the estimate, in accordance with applicable regulations, whereas actual future prices and costs may be materially higher or lower. For example, the reserve reports included in this Form 10-K were estimated using a calculated weighted average sales price of $2.32 per Mcf, which was based on the spot market price for gas on December 31, 2001. During 2001, the Company's net realized gas prices were as high as $10.02 per Mcf and as low as $1.24 per Mcf. Many factors will affect actual future net cash flows, including:

- the amount and timing of actual production,
- supply and demand for natural gas,
- curtailments or increases in consumption by natural gas purchasers, and
- changes in governmental regulations or taxation.

The timing of the production of oil and natural gas properties and of the related expenses affect the timing of actual future net cash flows from proved reserves and, thus, their actual present value. In addition, the 10% discount factor, which the Company is required to use to calculate PV-10 for reporting purposes, is not necessarily the most appropriate discount factor given actual interest rates and risks to which Evergreen's business or the oil and natural gas industry in general are subject.

The Company depends heavily on expansion and development of the Raton Basin.

All of Evergreen's proved reserves are in the Raton Basin and its future growth plans rely heavily on increasing production and reserves in the Raton Basin. The Company's proved reserves will decline as reserves are depleted, except to the extent the Company conducts successful exploration or development activities or acquires other properties containing proved reserves.

At December 31, 2001, the Company had estimated net proved undeveloped reserves of approximately 366 Bcf, which constituted approximately 35% of its total estimated net proved reserves. The Company's development plan includes increasing its reserve base through continued drilling and development of its existing properties in the Raton Basin. Evergreen cannot be sure that its planned

projects in the Raton Basin will lead to significant additional reserves or that it will be able to continue drilling productive wells at anticipated finding and development costs.

Evergreen's producing property acquisitions carry significant risks.

Evergreen's recent growth is due in part to acquisitions of producing properties. The successful acquisition of producing properties requires an assessment of a number of factors beyond the Company's control. These factors include recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities. These assessments are inexact and their accuracy is inherently uncertain. In connection with these assessments, the Company performs a review of the subject properties that 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 does not inspect every well. Even when a well is inspected, structural and environmental problems are not necessarily discovered. Normally, Evergreen acquires interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, competition for producing oil and gas properties is intense and many of its competitors have financial and other resources substantially greater than those available to the Company. Therefore, Evergreen cannot assure you that it will be able to acquire oil and gas properties that contain economically recoverable reserves or that it will acquire such properties at acceptable values.

The Company's industry is highly competitive.

Major oil companies, independent producers and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to operate properties. Many of the Company's competitors have financial and technological resources vastly exceeding those available to Evergreen. Many oil and gas properties are sold in a competitive bidding process in which the Company may lack technological information or expertise available to other bidders. The Company cannot be sure that it will be successful in acquiring and developing profitable properties in the face of this competition.

The oil and gas exploration business involves a high degree of business and financial risk.

The business of exploring for and, to a lesser extent, developing oil and gas properties is an activity that involves a high degree of business and financial risk. Property acquisition decisions generally are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately the ultimate production potential, if any, of a particular property or well. Moreover, the successful completion of an oil or gas well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomic or marginally economic.

The Company's business is subject to operating hazards that could result in substantial losses.

The oil and natural gas business involves operating hazards such as well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause the Company substantial losses. In addition, the Company may be held liable for environmental damage caused by previous owners of property it owns or leases. As a result, the Company may face substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause Evergreen to incur losses. An event that is not fully covered by insurance for example, losses resulting from pollution and environmental risks, which are not fully insurable could have a material adverse effect on the Company's financial condition and results of operations.

Exploratory drilling is an uncertain process with many risks.

Exploratory drilling involves numerous risks, including the risk that the Company will not find any commercially productive natural gas or oil reservoirs. The cost of drilling, completing and operating wells is often uncertain, and a number of factors can delay or prevent drilling operations, including:

unexpected drilling conditions,

pressure or irregularities in formations,

equipment failures or accidents,

adverse weather conditions,

compliance with governmental requirements, and

shortages or delays in the availability of drilling rigs and the delivery of equipment.

The Company's future drilling activities may not be successful, nor can Evergreen management be sure that the Company's overall drilling success rate or its drilling success rate for activity within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on the Company's results of operations and financial condition. Also, Evergreen may not be able to obtain any options or lease rights in potential drilling locations that it identifies. Although the Company has identified numerous potential drilling locations, management cannot be sure that Evergreen will ever drill them or that it will produce natural gas from them or any other potential drilling locations.

Hedging transactions may limit the Company's potential gains or expose the Company to loss.

To manage Evergreen's exposure to price risks in the marketing of its natural gas, the Company enters into natural gas fixed price physical delivery contracts as well as commodity price swap contracts from time to time with respect to a portion of its current or future production. While intended to reduce the effects of volatile natural gas prices, these transactions may limit the Company's potential gains if natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose Evergreen to the risk of financial loss in certain circumstances, including instances in which:

the Company's production is less than expected,

there is a widening of price differentials between delivery points for the Company's production and the delivery point assumed in the hedge arrangement,

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

a sudden, unexpected event materially impacts natural gas prices.

The Company may face unanticipated water disposal costs.

Based on the Company's previous experience with coal bed methane gas production in the Raton Basin, management believes that the State of Colorado will continue to routinely approve permits for the use of well-site pits, water disposal wells and evaporation ponds for the disposal of produced water. Where groundwater produced from the Raton Basin coal seams will not exceed surface discharge permit levels, and in many cases will meet state and federal primary drinking water standards, Evergreen can lawfully discharge the water into arroyos and surface waters pursuant to permits it has obtained from the State of Colorado. All of these disposal options require a laboratory analysis program to ensure compliance with state permit standards. Additionally, the Company contracts with

an independent water sampling company that collects the water samples and monitors the Company's water management program. These monitoring costs are directly related to the number of well-site pits, evaporation ponds and discharge points.

Where water of lesser quality is discovered or the Company's wells produce water in excess of the applicable volumetric permit limits, Evergreen may have to drill additional disposal wells to re-inject the produced water back into deep underground rock formations. Produced water is currently injected at seven such wells and permits to drill two more of these underground injection control (UIC) wells are pending. The costs to dispose of this produced water may increase, which could have a material adverse effect on the Company's operations in this area, if any of the following occur: (1) the Company cannot obtain future permits from the State of Colorado, (2) water of lesser quality is discovered, (3) the Company's wells produce excess water or (4) new laws or regulations require water to be disposed of in a different manner.

Evergreen has been the defendant in a lawsuit under the federal Water Pollution Control Act, or Clean Water Act, relating to regulatory requirements for its water disposal from certain of its Raton Basin wells.

The Company has limited protection for its technology and depends on technology owned by others.

The Company uses operating practices that management believes are of significant value in developing coal bed methane resources. In most cases, patent or other intellectual property protection is unavailable for this technology. The Company's use of independent contractors in most aspects of its drilling and some completion operations makes the protection of such technology more difficult. Moreover, the Company relies on technological expertise of the independent contractors that it retains for its oil and gas operations. The Company has no long-term agreements with these contractors and management cannot be sure that the Company will continue to have access to this expertise.

The Company's industry is heavily regulated.

Federal, state and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of oil and gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment, and restoration.

The Company must comply with complex environmental regulations.

The Company's operations are subject to complex and constantly changing environmental laws and regulations adopted by U.S. federal, state and local governmental authorities as well as by foreign governments where the Company is engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could have a material adverse effect on its business. State, federal and local environmental agencies have relatively little experience with the regulation of coal bed methane operations, which are technologically different from conventional oil and gas operations. This inexperience has created uncertainty regarding how these agencies will interpret air, water and waste requirements and other regulations to coal bed methane drilling, fracture stimulation methods, production and water disposal operations. Evergreen will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. The Company could face significant liabilities to the government and third parties for

discharges of oil, natural gas or other pollutants into the air, soil or water, and Evergreen could have to spend substantial amounts on investigations, litigation and remediation. The Company cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not materially adversely affect its results of operations and financial condition. As a result, the Company may face material indemnity claims with respect to properties it owns or has owned.

The Company's business depends on transportation facilities owned by others.

The marketability of the Company's gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. Although the Company has some contractual control over the transportation of its product, material changes in these business relationships could materially affect its operations. Federal and state regulation of gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, and general economic conditions could adversely affect the Company's ability to produce, gather and transport natural gas.

Market conditions could cause the Company to incur losses on its transportation contracts.

The Company has gas transportation contracts that require it to transport minimum volumes of natural gas. If the Company ships smaller volumes, it may be liable for the shortfall. Unforeseen events, including production problems or substantial decreases in the price for natural gas, could cause the Company to ship less than the required volumes, resulting in losses on these contracts. See Note 12 to the Consolidated Financial Statements.

The Company's international operations are subject to risks of doing business abroad.

Evergreen holds exploration licenses onshore in the United Kingdom, in Northern Ireland and the Republic of Ireland, and in northern Chile. The Company also holds an interest in offshore exploration in the Falkland Islands. International operations are subject to political, economic and other uncertainties, including, among others, risk of war, revolution, border disputes, expropriation, re-negotiation or modification of existing contracts, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes and other uncertainties arising out of foreign government sovereignty over Evergreen's international operations.

The Company depends on key personnel.

Evergreen's success will continue to depend on the continued services of its executive officers and a limited number of other senior management and technical personnel. Loss of the services of any of these people could have a material adverse effect on the Company's operations. The Company does not have employment agreements with any of the executive officers.

The Company does not pay dividends.

The Company has never declared nor paid any cash dividends on its common stock and management has no intention to do so in the near future.

The Company's articles of incorporation and bylaws have provisions that discourage corporate takeovers and could prevent shareholders from realizing a premium on their investment.

The Company's articles of incorporation and bylaws contain provisions that may have the effect of delaying or preventing a change in control. These provisions, among other things, provide for noncumulative voting in the election of the board and impose procedural requirements on shareholders

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who wish to make nominations for the election of directors or propose other actions at shareholders' meetings. Also, the Company's articles of incorporation authorize the Board to issue up to 24,900,000 shares of preferred stock without shareholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the Board may determine. 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 shareholders for their common stock.

On July 7, 1997 Evergreen's Board of Directors adopted a shareholder rights agreement, pursuant to which uncertificated stock purchase rights were distributed to shareholders of the Company at a rate of one right for each share of common stock held of record as of July 22, 1997. The rights plan is designed to enhance the Board's ability to prevent an acquirer from depriving shareholders of the long-term value of their investment and to protect shareholders against attempts to acquire Evergreen by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover of Evergreen not supported by the Board, including a takeover that may be desired by a majority of the Company's shareholders or involving a premium over the prevailing stock price.

The Company's stock price has been and is likely to continue to be volatile.

The market price of Evergreen common stock has been volatile. During 2001, the sale price of the common stock on the NYSE has ranged from a low of $29.45 per share to a high of $50.99 per share. The market price of the Company's common stock is subject to many factors, including:

- prices for oil and natural gas;
- general stock market conditions;
- conditions in the Company's industry;
- changes in the Company's revenues and earnings; and
- changes in analyst recommendations and projections.

ITEM 2. PROPERTIES

Operations

The Company's wholly-owned operating subsidiary, EOC, is primarily responsible for drilling, evaluation and production activities associated with various properties. As of February 15, 2002, EOC was serving as operator for approximately 725 gross producing wells owned by the Company.

The Company believes that, as operator, it is in a better position to control costs, safety and timeliness of work as well as other critical factors affecting the economics of a well or a property, including maintaining good community relations.

EOC presently operates wells which represent 100% of Evergreen's proved reserves.

Natural Gas Reserves

The table below sets forth the Company's quantities of proved reserves, as audited as of December 31, 2001 and 2000 by independent petroleum engineers Netherland Sewell & Associates, Inc. ("NSAI"). For the year ended December 31, 1999, the proved reserves were audited by both NSAI and Resource Services International, Inc. All proved reserves are located in the continental U.S., and the present value of estimated future net revenues from these reserves was calculated on a non-escalated price basis discounted at 10 percent per year as of periods indicated. There has been no major discovery or other favorable or adverse event that is believed to have caused a significant change in estimated proved reserves subsequent to December 31, 2001.

	December 31,		
	2001	**2000**	**1999**
Proved Developed Gas Reserves (MMcf)	684,167	544,211	334,805
Proved Undeveloped Gas Reserves (MMcf)	366,476	330,315	224,614
Total Proved Gas Reserves (MMcf)	1,050,643	874,526	559,419
Future Net Revenues (before future income tax expenses) (in thousands)	$ 1,336,302	$ 6,844,254	$ 820,983
Present Value of Future Net Revenues (before future income tax expenses) (in thousands)	$ 598,462	$ 2,920,166	$ 331,383

Reference should be made to Note 15 (Supplemental Oil and Gas Information) to the Consolidated Financial Statements for additional information pertaining to the Company's proved oil and gas reserves. During fiscal 2001, the Company did not file any reports that included estimates of total proved net oil or gas reserves with any federal agency other than the Securities and Exchange Commission and the Department of Energy.

Sales

The following table sets forth the Company's net natural gas sales for the periods indicated.

	Year Ended December 31,		
	2001	2000	1999
Natural Gas (MMcf)	30,807	19,521	13,656

Average Sales Prices, Lease Operating Expenses, Transportation Costs and Production Taxes

The following table sets forth the average sales price and the average lease operating expenses, transportation costs and production and property taxes per Mcf, for the periods indicated.

	Year Ended December 31,		
	2001	2000	1999
Average sales price of natural gas (per Mcf) *	$ 3.89	$ 3.03	$ 1.96
Lease operating expenses	$ 0.40	$ 0.38	$ 0.31
Transportation costs	$ 0.31	$ 0.30	$ 0.29
Production and property taxes	$ 0.18	$ 0.13	$ 0.08

* Includes effects of hedging transactions

Productive Wells

As of December 31, 2001, Evergreen had 713 gross and 681 net producing wells. The Company had no producing oil wells as of that date. Productive wells are producing wells and wells capable of production, including shut-in wells.

Acreage

At December 31, 2001, Evergreen held developed and undeveloped acreage as set forth below:

	Developed Acres		Undeveloped Acres		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Raton Basin	171,657	157,047	102,002	66,411	273,659	223,458
United Kingdom			452,000	452,000	452,000	452,000
Falkland Islands			400,600	160,200	400,600	160,200
Chile			1,200,000	1,200,000	1,200,000	1,200,000
Northern Ireland & Republic of Ireland			1,085,000	1,085,000	1,085,000	1,085,000
Alaska and other			87,705	80,661	87,705	80,661
Total	171,657	157,047	3,327,307	3,044,272	3,498,964	3,201,319

Developed Acres	Undeveloped Acres	Total

The following table sets forth the expiration dates of the gross and net acres subject to domestic leases summarized in the table of undeveloped acreage.

	Acres Expiring	
	Gross	Net
Twelve Months Ended:		
December 31, 2002 and later	2,761	1,604

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Drilling Activities

The Company's drilling activities for the periods indicated are set forth below:

	Year Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Domestic						
Exploratory Wells						
Productive	1	1	2	2		
Dry						
Total	1	1	2	2		
Development Wells						
Productive	145	137	100	97	85	83
Water Disposal			3	3	2	
Dry						
Total	145	137	103	100	87	83
International						
Exploratory Wells						
Productive	5		9			
Dry	1					
Total	6		9			

Coal Bed Methane Versus Traditional Natural Gas

Methane is the primary commercial component of the natural gas stream produced from traditional gas wells. Methane also exists in its natural state in coal seams. Natural gas produced from traditional wells also contains, in varying amounts, other hydrocarbons. However, the natural gas produced from coal beds generally contains only methane and, after simple water dehydration, is pipeline-quality gas.

Coal bed methane production is similar to traditional natural gas production in terms of the physical producing facilities and the product produced. However, the subsurface mechanisms that allow the gas to move to the wellbore and the producing characteristics of coal bed methane wells differ greatly from traditional natural gas production. Unlike conventional gas wells, which require a porous and permeable reservoir, hydrocarbon migration and a natural structural and/or stratigraphic trap, coal bed methane gas is trapped in the molecular structure of the coal itself until released by pressure changes resulting from the removal of in situ water or natural gas in the micropore system.

Methane is created as part of the coalification process, though coals vary in their methane content per ton. In addition to residing in open spaces in the coal structure, methane is absorbed onto the inner coal surfaces. When the coal is hydraulically fracture stimulated and exposed to lower pressures through the de-watering process, the gas leaves (desorbs from) the coal. Whether a coal bed will produce commercial quantities of methane gas depends on the coal quality, its original content of gas per ton of coal, the thickness of the coal beds, the reservoir pressure and the existence of natural fractures and cleating (permeability) through which the released gas can flow to the wellbore. Frequently, coal beds are partly or completely saturated with water. As the water is produced, internal pressures on the coal are decreased, allowing the gas to desorb from the coal and flow to the wellbore. Unlike traditional gas wells, new coal bed methane wells often produce water for several months and then, as the water production decreases, natural gas production increases as the coal seams de-water.

In order to establish commercial gas production rates, a permanent conduit between the individual coal seams and the wellbore must be created. This is accomplished by hydraulically creating, and propping open with special quality sand, artificial fractures within the coal seams (known as "fracing" in the industry) so the pathway for water and gas migration to the wellbore is enhanced. These fractures are filled (propped) with uniform sized sand and become the enhanced conduits for water and methane to reach the well. The ability of gas to move through the coal to the wellbore is the key determinant of the rate at which a well will produce.

Raton Basin Properties and Operations

The Raton Basin is approximately 80 miles long and 50 miles wide, located in southern Colorado and northern New Mexico. The Raton Basin contains two coal bearing formations, the Vermejo formation coals located at depths of between 450 and 4,000 feet and the shallower Raton formation coals, located at depths from the surface to approximately 3,000 feet. To date, the majority of Evergreen's production has been from the Vermejo formation coals; however, the Raton formation coal seams and interbedded sandstones are now being successfully developed as well.

Development History

Exploration for coal bed methane began in the Raton Basin in the late 1970s and continued through the late 1980s, with several companies drilling and testing over 100 wells during this period. The absence of a pipeline to transport gas out of the Raton Basin prevented full-scale development until January 1995, when CIG constructed the Picketwire Lateral.

Since December 1991, the Company has acquired oil and gas leases covering approximately 274,000 gross acres in the Raton Basin. The initial 70,000 acres were acquired in 1991 with additional acreage purchased from individual owners under various lease terms. Additional acreage positions and production have been increased by purchases in July 1998 and December 1998 and as discussed below.

Effective September 1, 2000, the Company acquired approximately 24,000 gross acres of producing coal bed methane properties in the Raton Basin for $181.5 million from an affiliate of KLT Gas, Inc., which is an indirect wholly-owned subsidiary of Kansas City Power & Light Company. The purchase was accounted for using the purchase method of accounting. At closing, Evergreen paid total consideration of $176 million, consisting of approximately $70 million in cash, $100 million in mandatory redeemable preferred stock and 201,748 shares of common stock valued at $6 million. In addition to the consideration paid at the closing of the acquisition, on January 5, 2001, the Company delivered 116,009 additional shares of common stock valued at $4 million, under the terms of the acquisition agreement, because the average of the monthly settle prices for the 2001 NYMEX natural gas contracts exceeded $4.465 per MMBtu. Also, as additional purchase consideration, Evergreen paid monthly net profits interest payments and recorded various other post closing adjustments of $1.5 million. Evergreen redeemed the mandatory redeemable preferred stock on December 22, 2000 using new borrowings under its credit facility. The preferred stock earned dividends from September 1, 2000 through December 22, 2000 of $2,929,000, reflecting an annual rate of 9.5%.

Effective June 1, 2001, Evergreen purchased an additional 35% ownership interest in Lorencito Gas Gathering Company, LLC, or LGG, and an additional 35% working interest in approximately 17,800 acres of producing coal bed methane properties in the Lorencito Canyon region of the Raton Basin for approximately $20 million. As a result of the purchase, Evergreen now owns 85% of LGG and an 80% working interest in the Lorencito properties. The acquired property interests represented an estimated 40 Bcf of proven net gas reserves at the time of acquisition. Approximately 63% of the reserves acquired were classified as proved developed with the remaining 37% classified as proved undeveloped. All of the estimated reserves were assigned to the Vermejo and Raton group of coals.

Currently, Evergreen has a 100% working interest in three federal units, the Spanish Peaks Unit, the Cottontail Pass Unit and the Sangre de Cristo Unit. The total gross acreage in the federal units is approximately 134,000 acres. The Company is the named the operator for all three of these units. Formation of a unit simplifies lease maintenance so that the Company, as the operator, can base development decisions within the unit on technical, geologic and geophysical data and operational and cultural considerations rather than on the fulfillment of lease term obligations.

Because of the inclusion of federal leases in the unit, administration within a federal unit is governed by federal rules. Production from any well in the unit area will maintain all of the leases beyond their primary terms. In October 1997, the first "participating area" was designated by the federal Bureau of Land Management under the Unit Agreement. Gas production in the participating area will be pooled and shared by the royalty owners, overriding royalty owners and working interest owners in that area in proportion to their acreage ownership of the mineral estate in the area. The participating area will be adjusted annually to encompass additional acreage as additional wells are completed.

Evergreen also has working interests of between 75% and 100% in areas adjacent to the federal units, which include the Long Canyon and Lorencito areas and the Primero, Rita, Sarcillo and Weston tracts. These areas comprise approximately 140,000 acres.

Raton Basin Geology

In the Raton Basin, Evergreen produces methane almost entirely from the Vermejo coals, consisting of several individual seams ranging in thickness between 1 and 12 feet, and at drilling depths between 450 and 4,000 feet below the surface. The Vermejo total coal thickness ranges from 5 to 50 feet thick throughout the Raton Basin. It is thickest in the center of the Basin, which the Company's acreage surrounds. The coal beds and interbedded sedimentary rocks formed during the late Cretaceous to early Tertiary period, between 65 and 40 million years ago. The Raton Basin is a highly asymmetric downward fold in the earth's crust that is approximately 80 miles long north to south and about 50 miles wide east to west. Organic material accumulated in thick layers within coastal swamps in the Raton Basin and was subsequently buried and subjected to heat and pressure, which formed the coals. Since these coals were buried, continued mountain building, in combination with basin downwarping, created an extensive series of faults and fractures in the coals and surrounding rocks. Later, the area was intruded by hot liquid rock or "magma" from lower in the earth's crust, which cooled to form two large present day mountain structures in the center of the Raton Basin known as the Spanish Peaks. The magma moved up through existing faults and fractures and created additional fractures that radiate outward from the Spanish Peaks. As the magma cooled, its heat altered the surrounding rocks, including the Vermejo and Raton coal beds. Evergreen believes that the simultaneous downwarping of the Raton trough and Larimide age mountain building with subsequent relaxation (extension) and the additional heating provided by magmatic activity in the Raton Basin have matured the coals and enhanced the ability of the Vermejo and Raton coals to yield coal bed methane gas.

In the Raton Basin, Evergreen has found some coal seams to be continuous between wells over distances of several miles, though the thickness of these beds are variable. Individual wells are often completed to produce gas from 5 to 15 individual coal beds with individual thickness between 1 and 12 feet.

Coal Bed Methane Technology

The Company has developed what management believes to be effective procedures for fracing the Vermejo and Raton coals in its Raton Basin wells. In addition, the Company has developed well completion and specialized drilling techniques that are suited to the Raton Basin. Traditional gas wells

are drilled with the use of rotary drill bits cooled and lubricated by drilling fluids or "mud." Coal bed methane production is particularly sensitive to the natural permeability of the coals. Exposing the Raton Basin coals to drilling mud appears to significantly reduce the permeability of the coals by plugging the coal cleat system and natural fractures in the coals. Therefore, Evergreen uses percussion air drilling (similar to a jackhammer) without traditional drilling muds in drilling its wells. The Company is continually working to improve and enhance its technology expertise.

Water Production and Disposal

Based on the Company's experience in coal bed methane production in the Raton Basin and extensive laboratory analysis of water samples taken from its coal bed methane wells, management believes that the groundwater produced from the Raton Basin coal seams will not exceed permit levels and will be suitable for discharge into arroyos, surface water, well-site pits or evaporation ponds pursuant to permits obtained from the State of Colorado. Recent gas analyses confirm that the gas stream is 99% pure methane and lacks other hydrocarbon sources of contamination. In some cases the water is of such quality that it can be discharged to arroyos and surface water under general water discharge permits issued to the Company by the State of Colorado. These permits give Evergreen the flexibility to add water discharge points on an as-needed basis with minimal administrative paperwork and within 30 days or less of application. Evergreen has in excess of 300 approved discharge points and has received an increase in the total volume of water permitted for surface discharge. Approval of these requests is uncertain and is dependent upon completion of additional study by the State of Colorado. Additionally, the Company contracts with an independent water sampling company that collects the water samples and monitors all the Company's water management program. These monitoring costs are directly related to the number of well-site pits, evaporation ponds and discharge points. Because it originates in a natural groundwater system, there is some uncertainty whether water currently being discharged to streams and arroyos will continue to meet permit standards for total iron and suspended solids. Water not meeting these discharge standards can be disposed of in well-site pits and evaporation ponds.

When water of lesser quality is discovered or Evergreen's wells produce water in excess of the applicable permit limits, the Company may have to drill additional disposal wells to re-inject the produced water into deeper sandstone horizons. This would also have to be accomplished through an appropriately issued permit that has been routinely approved in the past.

Raton Basin Production

Evergreen's natural gas sales from the Raton Basin did not commence until the completion of a pipeline system in January 1995, which connected its Raton Basin wells to the CIG pipelines. From January 1995 through December 2001, the Company sold an aggregate of approximately 82.5 Bcf of coal bed methane gas from the Raton Basin. Evergreen's net daily gas sales are currently averaging approximately 97.5 MMcf per day. Because of the importance of removing water from the coal seams to enhance gas production, the Company expects to continue production from more modest wells because of the beneficial ambient effect of pressure reduction in adjacent, more productive wells. Each well creates its own "cone of depression" around the wellbore. The Company believes that some of its Raton Basin wells on adjacent 160-acre sites have already created overlapping cones of depression, enhancing gas production in each well within this pattern. In some cases this pattern of interference can be enhanced by drilling a fifth well in the 640-acre section.

Raton Basin gas contains insignificant amounts of contaminants, such as hydrogen sulfide, carbon dioxide or nitrogen, that are sometimes present in conventional natural gas production. Therefore, the properties of Raton Basin gas, such as heat content per unit volume (Btu), are close to the average properties of pipeline gas from conventional gas wells.

United Kingdom

In 1991 and 1992, Evergreen's wholly-owned subsidiary, Evergreen Resources (U.K.) Ltd. ("ERUK"), was awarded seven onshore United Kingdom hydrocarbon exploration licenses for the development of coal bed methane gas and conventional hydrocarbons. These original licenses provided ERUK with the largest onshore acreage position in the U.K.

Selection of the licensed areas was made after evaluating geological, geophysical, petrophysical and measured methane gas content databases. The majority of the original database was acquired through technology sharing agreements with British Coal Corporation, which shared relevant available data on the six basins and granted use of this data to ERUK. ERUK has augmented this data with proprietary seismic and coal bed methane well data and also geologic data from the British Geologic Survey, and other sources.

During the period from 1992 to 1994, Evergreen conducted seismic work and drilled three wells under two of the original licenses. The wells encountered 30 feet to 80 feet of gross coal intervals. Two of the wells were hydraulically fracture stimulated and one was tested for permeability. Following extensive production testing, none of the three wells produced gas in economic quantities. The three wells are presently shut-in.

In 1997, under a new onshore licensing regime implemented by the U.K. Department of Trade and Industry, the Company converted its original licenses to new onshore licenses, called Petroleum Exploration and Development Licenses. Under these new licenses, the Company retains approximately 452,000 acres, which were high-graded for coal bed methane and conventional hydrocarbon potential. These licenses provide up to a 30-year term with optional periodic relinquishment of portions of the licenses, subject to future development plans. There are no royalties or burdens encumbering these licenses.

Management believes that a major coal bed methane resource exists within the areas subject to the current licenses. However, further evaluation will be required to confirm this belief and determine the economic viability of extracting any reserves. Evaluation is expected to occur on a license-by-license basis because success or lack of success on one license may not be translated to similar results on other licenses or separate geologic basins.

In April 2000, the Company began drilling activities on its coal bed methane gas project in the U.K. A total of nine wells were drilled during 2000, of which five were coal bed methane wells, three were mine-gas interaction wells and one was a gob gas well. Total well depth of the coal bed methane and interaction wells ranged from 2,213 feet to 3,960 feet for coal bed methane wells and 1,485 feet to 2,156 feet for the mine-gas interaction wells. Total coal thickness ranged from 75 feet to 97 feet of coal. The gob gas well has a total depth of 879 feet from an approximate six foot gob thickness. During 2000, the Company fracture stimulated the five coal bed methane wells using its own pumping equipment in conjunction with a new completion technology utilizing "coiled tubing." Evergreen believes this is the first time that nitrified foam fracs using coiled tubing technology have been used in the U.K. Coiled tubing completions isolate individual coal seams that are to be fraced versus fracing a group of coals using current technology. Coiled tubing also provides for a better in-zone propped fracture with increased length at lower overall costs.

The Company experienced delays in its proposed 2001 drilling program throughout 2001 due to the regulatory environment, which included required approvals from local planning commissions for drilling permits, and was consequently unable to complete its anticipated drilling program for 2001. Drilling operations on the first of four planned gob gas wells expected to be drilled in 2002 on Evergreen's United Kingdom coal bed methane acreage began February 5, 2002. The Company expects to obtain planning permission for the remaining three gob gas wells which are expected to be drilled before the end of the second quarter of 2002. Additionally, the Company intends to fracture stimulate

three existing mine gas interaction wells in the United Kingdom late in the first quarter or early in the second quarter of 2002.

Northern Ireland and Republic of Ireland

In March and April 2001, the Company acquired 100% working interest in 1,085,000 acres of prospective tight gas sand properties in Northern Ireland (605,000 acres) and in the Republic of Ireland (480,000 acres) for total consideration of $1,250,000 (23,200 shares of Evergreen common stock valued at $750,000 and $500,000 in cash) plus a small retained net profits interest. Evergreen has drilled four wells in Northern Ireland and two wells in the Republic of Ireland to depths ranging from approximately 2,700 feet to 4,400 feet. Evergreen is in the process of completing five of these six wells. Three wells have been fracture stimulated to date. The first well took nine stages and 358,000 lbs. of sand, while the second well was completed in six stages with 455,500 lbs. of sand and the third well completed in one stage and 66,000 lbs. of sand. All five wells are expected to be completed by the end of April 2002. After completion of each of the wells, the Company will start bottom hole pressure and flowback tests for 35 to 45 days.

Other Domestic and International Projects

Evergreen holds a 100% working interest in approximately 64,000 acres of prospective coal bed methane properties in Alaska and exploratory acreage in northern Colorado. During 2002, the Company expects to drill up to 10 wells in the Pioneer Unit on its Alaska acreage. The Company continues to evaluate additional domestic properties. Evergreen also holds interests in two international projects located in northern Chile and the Falkland Islands. The Company is currently evaluating the hydrocarbon potential of these prospects and anticipates that they will require only modest capital expenditures through 2002.

Office and Operations Facilities

The Company leases its corporate offices in Denver, Colorado. The Company has an office lease for approximately $620,000 per year through 2008. The Company believes its office space will be sufficient for the foreseeable future.

ITEM 3. LEGAL PROCEEDINGS

Evergreen is not engaged in any material legal proceedings to which the Company or its subsidiaries are a party or to which any of its property is subject.

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

Not applicable.

PART II

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

Price Range of Common Stock

Evergreen's common stock has been listed on the New York Stock Exchange under the market symbol "EVG" since September 8, 2000. Prior to then it was included for quotation in the Nasdaq National Market under the symbol "EVER." The following table sets forth the range of high and low sales prices per share of common stock for the periods indicated.

	High	Low
Year Ended December 31, 1999		
First Quarter	$ 21.63	$ 14.50
Second Quarter	25.75	19.00
Third Quarter	28.50	21.38
Fourth Quarter	24.06	14.84
Year Ended December 31, 2000		
First Quarter	$ 26.31	$ 17.75
Second Quarter	30.06	21.00
Third Quarter	34.94	24.75
Fourth Quarter	40.13	27.13
Year Ended December 31, 2001		
First Quarter	$ 43.50	$ 29.45
Second Quarter	50.99	34.80
Third Quarter	42.35	30.65
Fourth Quarter	43.00	32.04

On February 28, 2002, the last reported sale price of the common stock on the NYSE was $41.80 per share. As of February 28, 2002, there were approximately 1,500 holders of record of the common stock.

Dividend Policy

The Company has not declared nor paid and does not anticipate declaring or paying any dividends on its common stock in the near future. Any future determination as to the declaration and payment of dividends will be at the discretion of the Company's board of directors and will depend on then existing conditions, including the Company's financial condition, results of operations, contractual restrictions, capital requirements, business prospects, and such other factors as the board deems relevant.

Sale of Senior Convertible Notes

On December 18, 2001, the Company sold $100 million of 4.75% senior convertible notes due 2021, receiving proceeds, after deducting commissions, of $97 million. The notes are convertible under certain circumstances into 2 million shares of Evergreen common stock at a per share price of $50.00. The notes were sold to initial purchasers, who in turn sold them to qualified institutional buyers, in a private placement pursuant to Section 4(2) of the Securities Act of 1933, as amended, and may be resold to qualified institutional buyers on the PORTAL market. The Company intends to file a registration statement on Form S-3 relating to the resale of the notes and the common stock into which the notes are convertible with the Securities and Exchange Commission.

ITEM 6. SELECTED FINANCIAL DATA

The selected consolidated financial information presented below for the years ended December 31, 2001, 2000, 1999, 1998 and 1997 is derived from the Consolidated Financial Statements of the Company.

This information should be read in conjunction with the Consolidated Financial Statements and Notes thereto and Management's Discussion and Analysis of Financial Condition and Results of Operations. Effective the fourth quarter 2000, the Company adopted Emerging Issues Task Force Issue 00-10, "Accounting for Shipping and Handling Fees and Costs," which provided that amounts billed for transportation and other shipping and handling fees should be classified as revenues and that the costs should be classified as operating expenses and not netted against natural gas revenues. With the adoption of this issue, the Company reclassified prior years' costs to conform with this presentation. As discussed in Note 3 to the Consolidated Financial Statements, the Company acquired certain properties in the KLT property acquisition and included the operations of these properties in its consolidated operations beginning September 1, 2000. As discussed in Note 14 to the Consolidated Financial Statements, effective February 18, 1999, Evergreen sold its 49% interest in Maverick Stimulation Company ("Maverick") and recorded a gain net of tax of approximately $452,000 or $0.03 per diluted share. This transaction was accounted for as a discontinued operation and the results of operations have been excluded from continuing operations in the consolidated statements of income for all periods

presented. Certain reclassifications have been made to prior financial statements to conform with the current presentation.

	Years Ended December 31,				
	2001	**2000**	**1999**	**1998**	**1997**
	(In Thousands, Except Per Share Amounts)				
Statement of Operations Data					
Revenues:					
Natural gas revenues	$ 119,745	$ 59,128	$ 26,722	$ 21,582	$ 13,536
Interest and other	1,025	565	207	178	136
Total revenues	120,770	59,693	26,929	21,760	13,672
Expenses:					
Lease operating expenses	12,228	7,475	4,245	2,280	1,297
Transportation costs	9,524	5,902	4,001	2,519	1,398
Production and property taxes	5,472	2,567	1,146	1,077	710
Depreciation, depletion and amortization	16,212	8,190	4,757	3,860	2,794
General and administrative	6,985	4,364	3,024	1,933	1,286
Interest	8,331	3,330	1,927	1,870	777
Other	653	178	175	286	259
Total expenses	59,405	32,006	19,275	13,825	8,521
Income from continuing operations before income taxes	61,365	27,687	7,654	7,935	5,151
Income tax provision deferred	22,838	10,695	2,979	3,062	
Income from continuing operations	38,527	16,992	4,675	4,873	5,151
Discontinued operations					
Gain on disposal of discontinued operations, net			452		
				339	313

	Years Ended December 31,				
Equity in earnings of discontinued operations, net					
Net income	38,527	16,992	5,127	5,212	5,464
Preferred stock dividends		(2,929)			(400)
Net income attributable to common stockholders	$ 38,527	$ 14,063	$ 5,127	$ 5,212	$ 5,064
Basic income per common share					
From continuing operations	$ 2.08	$ 0.91	$ 0.36	$ 0.47	$ 0.50
From discontinued operations			0.03	0.03	0.03
Basic income per common share	$ 2.08	$ 0.91	$ 0.39	$ 0.50	$ 0.53
Diluted income per common share					
From continuing operations	$ 1.98	$ 0.87	$ 0.34	$ 0.44	$ 0.48
From discontinued operations			0.03	0.03	0.03
Diluted income per common share	$ 1.98	$ 0.87	$ 0.37	$ 0.47	$ 0.51
Statement of Cash Flows Data					
Net cash provided by (used in):					
Operating activities	$ 90,113	$ 31,274	$ 12,731	$ 12,147	$ 6,457
Investing activities	(122,547)	(144,196)	(43,864)	(47,202)	(19,259)
Financing activities	31,457	116,269	30,471	34,260	12,253

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	As of December 31,				
	2001	2000	1999	1998	1997
	(In Thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 3,024	$ 4,034	$ 651	$ 1,334	$ 2,103
Working capital (deficit)	(6,793)	6,850	(62)	(468)	(118)
Total assets	556,025	450,745	184,369	139,626	87,306
Total long-term obligations	181,000	149,748	15,500	47,045	14,841
Total stockholders' equity	314,940	266,852	153,510	79,679	64,152

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

The following information should be read in conjunction with the Consolidated Financial Statements and Notes presented elsewhere in this Form 10-K. The Company follows the full-cost method of accounting for oil and gas properties. See "Summary of Accounting Policies," included in Note 1 to the Consolidated Financial Statements.

General

Evergreen is an independent energy company engaged in the operation, development, production, exploration and acquisition of natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Its current operations are principally focused on developing and expanding its coal bed methane projects located in the Raton Basin in southern Colorado. The Company has begun coal bed methane projects in the United Kingdom and Alaska. In addition, the Company is engaged in the exploration of natural gas prospects in Northern Ireland and the Republic of Ireland, and owns additional interests in other domestic and international areas.

The Company had 681 net producing gas wells at December 31, 2001. The Company's average net daily natural gas sales are currently approximately 97.5 MMcf.

The following table sets forth certain operating data of the Company for the periods presented:

	Years Ended December 31,				
	2001	2000	1999	1998	1997
Natural gas sales (MMcf)	30,807	19,521	13,656	10,021	6,402
Average daily sales (MMcf)	84.4	53.3	37.4	27.5	17.5
Average realized sales price per Mcf*	$ 3.89	$ 3.03	$ 1.96	$ 2.15	$ 2.11
Cost Per Mcf:					
Lease operating expenses	$ 0.40	$ 0.38	$ 0.31	$ 0.23	$ 0.20
Transportation costs	0.31	0.30	0.29	0.25	0.22
Production and property taxes	0.18	0.13	0.08	0.11	0.11
Depreciation, depletion and amortization	0.53	0.42	0.35	0.39	0.44
General and administrative	0.23	0.22	0.22	0.19	0.20
Interest expense	0.27	0.17	0.14	0.19	0.12

* Includes effects of hedging

Results of Operations

Year ended December 31, 2001 compared to year ended December 31, 2000

Net income attributable to common stockholders was $38,527,000 or $1.98 per diluted share for the year ended December 31, 2001 versus net income of $14,063,000 or $0.87 per diluted share for the same period in 2000.

Natural gas revenues increased to $119,745,000 during the year ended December 31, 2001 from $59,128,000 in the prior year. The increase in natural gas revenues of $60,617,000, or 103%, was due to a 58% increase in sales volumes to 30.8 Bcf from 19.5 Bcf and a 28% increase in average gas prices to $3.89 per Mcf in 2001 from $3.03 per Mcf in 2000. The 28% increase in average gas prices was partially due to an increase in hedging gains to $13,895,000 in 2001 compared to $260,000 in 2000. The increase in sales volumes was due to increased drilling activity and the KLT and Lorencito property acquisitions, which occurred in September 2000 and June 2001, respectively. The number of net producing Raton Basin wells increased to 681 at December 31, 2001 from 491 at December 31, 2000.

Net sales from drilling operations increased by 23% to 20.1 Bcf (55.1 MMcf per day) in 2001 from 16.3 Bcf (44.5 MMcf per day) in 2000. Net sales from the acquired properties increased to 10.7 Bcf in 2001 from 3.2 Bcf in 2000. The increase in the property acquisition sales was primarily due to a full year of operations of the KLT properties in 2001 versus four months in 2000 and the addition of the Lorencito properties in mid-2001. On a daily sales comparison the average daily sales for the acquisition properties was 29.3 MMcf per day in 2001 versus 26.5 MMcf per day in 2000.

Interest and other income increased to $1,025,000 during the year ended December 31, 2001 as compared to $565,000 in 2000, an increase of 81%. The increase was primarily due to the accretion of a $500,000 discount on convertible preferred stock the Company purchased in February 2001. (See Note 13 to the Consolidated Financial Statements for more information.)

During the year ended December 31, 2001, lease operating expenses were $12,228,000 as compared to $7,475,000 in the prior year. The increase in lease operating expense was due to the increase in the number of producing wells, an increase in the number of compressors, an increase in field personnel, workover costs related to well repairs and maintenance costs for compressors. While overall lease operating expenses increased, lease operating expenses on a per Mcf basis remained generally consistent at $0.40 per Mcf for the year ended December 31, 2001 compared to $0.38 for the year ended December 31, 2000.

Transportation costs increased $3,622,000 from $5,902,000 for the year ended December 31, 2000 to $9,524,000 for the year ended December 31, 2001. The increase of 61% was primarily due to the 58% increase in sales volumes.

For the year ended December 31, 2001, production and property taxes were $5,472,000 or $0.18 per Mcf as compared to $2,567,000 or $0.13 per Mcf for the same period in the prior year. The increase in both total dollars and cost per Mcf was primarily due to higher natural gas prices. As a percentage of natural gas sales, production and property taxes were 4.6% and 4.3% for the years ending December 31, 2001 and 2000, respectively.

Depreciation, depletion and amortization expense for the year ended December 31, 2001 was $16,212,000 versus $8,190,000 in 2000. Depreciation, depletion and amortization expense increased to $0.53 per Mcf in 2001 as compared to $0.42 per Mcf in 2000. The increase in cost per Mcf was primarily due to the KLT property acquisition in September 2000, which had an acquisition cost of $1.12 per Mcf.

General and administrative expenses were $6,985,000 during the year ended December 31, 2001 versus $4,364,000 in 2000. The increase in 2001 of $2,621,000 was due to the expected increase in the overall growth in corporate activity. During 2001, personnel costs increased due to the addition of new staff, salary and bonus increases and related benefits, professional fees, insurance costs and office expense related to additional office space. Although the overall general and administrative expenses increased $2,621,000 for the year ended December 31, 2001, the cost per Mcf increased only slightly to $0.23 from $0.22 in the prior year.

Interest expense, net of capitalized amounts, was $8,331,000 during the year ended December 31, 2001 as compared to $3,330,000 in 2000. The $5,001,000 increase for 2001 over the prior year was due to the increased average outstanding balance on the revolving credit facility in 2001 of approximately $155 million compared to approximately $53 million in 2000. The increase in the average amount outstanding on the revolving credit facility was offset by a decrease in the average interest rate on the revolving credit facility during 2001 to approximately 6%. The increase in average borrowings was due to the funds used for redemption of the mandatory redeemable preferred stock in December 2000, the KLT property acquisition in September 2000 and the accelerated development in the Raton Basin during 2001.

Other expense of $653,000 for the year ended December 31, 2001 included a $307,000 charge to earnings related to the write-off of the majority of the assets of EnviroSeis, LLC, a wholly-owned 2-D seismic company.

In connection with the KLT property acquisition in September 2000, the Company issued $100 million in redeemable preferred stock with an annual dividend rate of 9.5%. Dividends of $2,929,000 were paid during the period ended December 31, 2000. The redeemable preferred stock was redeemed on December 22, 2000 with funds from the Company's line of credit.

The Company provided for deferred taxes for the first six months of 2001 at a rate of 38% and at a rate of 35.5% for the second half of 2001 versus 38.6% during 2000. The decrease in the tax rate was primarily due to state income tax credits the Company now expects to be able to utilize. The enterprise zone tax credits are due to the Company's development in Las Animas County. The Company had originally estimated that it would start to pay taxes in the second quarter of 2001. However, due to the reduction in natural gas prices, the increased drilling program and the related taxable deduction of intangible drilling costs and the utilization of net operating losses, the Company estimates that cash payments for taxes will not be required until 2003.

On a quarterly basis the Company is required to review the carrying value of its oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission. Under these rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the last day of the quarter and requires a write-down for accounting purposes if the ceiling is exceeded. At December 31, 2001, the spot price that the Company would have realized for its natural gas sales was $2.32 per Mcf. At this price level, the Company did not have a write-down as the present value of the Company's future net revenues, discounted at 10%, exceeded the Company's capitalized costs. If natural gas prices drop to lower levels during 2002 and future periods, the Company could be required to record a write-down of its capitalized costs.

Year ended December 31, 2000 compared to year ended December 31, 1999

Net income attributable to common stockholders was $14,063,000 or $0.87 per diluted share for the year ended December 31, 2000 versus net income of $5,127,000 or $0.37 per diluted share for the same period in 1999.

Natural gas revenues increased to $59,128,000 during the year ended December 31, 2000 from $26,722,000 in the prior year. The increase in natural gas revenues of $32,406,000, or 121% for the year ended December 31, 2000, compared to 1999 was due to a net gain of $260,000 recognized from hedging activities, an increase in sales volumes of 43% to 19.5 Bcf from 13.7 Bcf and a 55% increase in average gas prices to $3.03 per Mcf in 2000 from $1.96 per Mcf in 1999. The increase in sales volumes was partially due to increased drilling activity and the KLT property acquisition. At December 31, 2000, the number of net producing Raton Basin wells increased to 491 from 252 at December 31, 1999.

Interest and other income increased to $565,000 during the year ended December 31, 2000 as compared to $207,000 in 1999, an increase of 173%. The increase was due to increased cash flow in 2000 and equipment rental income.

During the year ended December 31, 2000, lease operating expenses were $7,475,000 or $0.38 per Mcf as compared to $4,245,000 or $0.31 per Mcf in the prior year. The increase in lease operating expense in 2000 as compared to 1999 was due to the increase in the number of producing wells, additional compressor expense, increase in field personnel and workover costs related to well repairs and maintenance costs for compressors. Lease operating expenses related to the wells from the KLT property acquisition were $1,311,000 for the year ended December 31, 2000 or $0.41 per Mcf.

Effective in the fourth quarter 2000, the Emerging Issues Task Force ("EITF") Issue 00-10, "Accounting for Shipping and Handling Fees and Costs," required transportation costs to be included in operating expenses versus netted against natural gas revenues. Reclassifications were made to prior periods to conform with this presentation. Transportation costs for the year ended December 31, 2000 were $5,902,000 or $0.30 per Mcf as compared to $4,001,000 or $0.29 per Mcf in 1999. The increase of $1,901,000 was primarily due to the increase in production from new wells and the KLT property acquisition.

For the year ended December 31, 2000, production and property taxes were $2,567,000 or $0.13 per Mcf as compared to $1,146,000 or $0.08 per Mcf for the same period in the prior year, due to higher natural gas prices.

Depreciation, depletion and amortization expense for the year ended December 31, 2000 was $8,190,000 versus $4,757,000 in 1999. Depreciation, depletion and amortization expense increased to $0.42 per Mcf in 2000 as compared to $0.35 per Mcf in 1999. The increase in cost per Mcf in 2000 as compared to 1999 was primarily due to the KLT property acquisition. Excluding acquisitions, the Company had an average finding cost of $0.25 per Mcf from the inception of its drilling activities in the Raton Basin while the average finding cost associated with the KLT property acquisition was $1.12 per Mcf.

General and administrative expenses were $4,364,000 during the year ended December 31, 2000 versus $3,024,000 in 1999. The increase in 2000 of $1,340,000 was due to the expected increase in the overall growth in corporate activity. During 2000, personnel costs increased due to the addition of new staff, salary increases, related benefits and insurance costs. Although the overall general and administrative expenses increased for the year ended December 31, 2000, the cost per Mcf remained at $0.22 in 2000, as in 1999. Through March 1999, EOC operated properties for various third party working interest owners and the related overhead charges received by EOC were netted against general and administrative expenses. The working interest owners sold those properties in January 1999. As such, EOC did not receive overhead payments for the operation of those properties after March 1999, which increased the Company's general and administrative expenses by $192,000 for the year ended December 31, 2000 as compared to 1999.

Interest expense was $3,330,000 during the year ended December 31, 2000 as compared to $1,927,000 in 1999. The $1,403,000 increase for 2000 over the prior year was due to increased average borrowings under the Company's line of credit. The increase in borrowings was due to the funds used for redemption of the mandatory redeemable preferred stock, the KLT property acquisition and continuing development in the Raton Basin.

On February 18, 1999, the Company sold its 49% interest in Maverick Stimulation Company ("Maverick") to the managing members of Maverick. The closing date was April 14, 1999. On that date, the Company received $2,258,000 in cash and was released from its debt guarantee with Maverick's bank. The Company recorded an after tax gain on the sale of its 49% interest of $452,000.

In connection with the KLT property acquisition, the Company issued $100 million in redeemable preferred stock with an annual dividend rate of 9.5%. Dividends of $2,929,000 were paid during the year ended December 31, 2000. The stock was redeemed on December 22, 2000 with funds from the Company's line of credit.

Liquidity and Capital Resources

Sources and Uses

The Company's primary sources of liquidity are cash provided by operations and debt financing. Capital markets have also been utilized in order to maintain the Company's indebtedness at moderate levels in order to provide sufficient financial flexibility to react to future opportunities. The Company's

primary needs for cash are for exploration, development and acquisitions of oil and gas properties and working capital obligations.

In December 2001, the Company issued $100 million in senior unsecured convertible notes, receiving net proceeds of $97 million. The notes are due in 2021 and bear interest at a fixed annual rate of 4.75%, which is to be paid in cash on June 15 and December 15 of each year. In addition to the interest discussed above, the Company will pay contingent interest to the holders of the notes if the average trading price of the notes for an established number of days exceeds 120% or more of the principal amount of the notes. The rate of contingent interest payable in respect to any six-month period will equal the greater of (1) a per annum rate equal to 5% of the Company's estimated per annum borrowing rate for senior non-convertible fixed-rate debt with a maturity date comparable to the notes or (2) 0.30% per annum. In no event may the contingent interest rate exceed 0.40% per annum. See Note 5 to the Consolidated Financial Statements.

The notes are general unsecured obligations, ranking on a parity in right of payment with all of Evergreen's existing and future senior indebtedness, and senior in right of payment with all of Evergreen's future subordinated indebtedness. The notes are due on December 15, 2021 but are redeemable at either the Company's option or the holder's option on other specified dates. The Company may redeem the notes at its option in whole or in part beginning on December 20, 2006, at 100% of their principal amount plus accrued and unpaid interest (including contingent interest). Holders of the notes may require the Company to repurchase the notes if a change in control of the Company occurs. Holders may also require the Company to repurchase all or part of the notes on December 20, 2006, December 15, 2011 and December 15, 2016 at a repurchase price of 100% of the principal amount of the notes plus accrued and unpaid interest (including contingent interest). On December 20, 2006, the Company may pay the repurchase price in cash, in shares of common stock, or in any combination of cash and common stock. On December 15, 2011 and December 15, 2016, the Company must pay the repurchase price in cash.

The notes are convertible into common stock of Evergreen under certain circumstances as discussed below at a conversion price of $50 per share, subject to certain adjustments. The notes can be converted at the option of the holder if for a specified period of time, the closing price of the Company's common stock exceeds 110% of the $50 conversion price or if the average trading value of the notes for a specified period of time is less than 105% of an average conversion value as defined by the indenture governing the notes. The notes may also be converted into common shares of the Company at the election of the holder upon notice of redemption, or at any time the notes are rated by either Moody's Investors Service, Inc. or Standard & Poor's Rating Group and the credit rating initially assigned to the notes by either such rating agency is reduced by two or more ratings levels, or upon the occurrence of certain corporate transactions including a change in control or the distribution to current holders of the Company's common stock, certain purchase rights or any other asset that has a value exceeding 10% of the sale price of the common stock on the day preceding the declaration date of the distribution of such assets.

The Company currently has a $200 million revolving credit facility with a bank group (the "Banks"). The credit facility is available through July 1, 2003. Advances pursuant to this credit facility are limited to a borrowing base, which is presently $200 million. The Company may elect to use either the London Interbank Offered Rate, or LIBOR, plus a margin of 1.125% to 1.50% or the Prime Rate plus a margin of 0% or 0.25%, with margins on both rates determined on the average outstanding borrowings under the credit facility. The borrowing base is redetermined semi-annually by the Banks based upon reserve evaluations of Evergreen's oil and gas properties. An average annual commitment fee of 0.3125% is charged quarterly for any unused portion of the credit line. The agreement is collateralized by all domestic oil and gas properties and guaranteed by substantially all of the Company's subsidiaries. The credit agreement also contains certain net worth, leverage and ratio covenants. At December 31, 2001 Evergreen had $81 million of outstanding borrowings under this

credit facility, with a current average interest rate of 3.5%. The Company was in compliance with all loan covenants at December 31, 2001 and 2000. The Company is currently in negotiations with the Banks to extend the maturity of the credit facility an additional two years to July 2005. The extension of the credit agreement is expected in March 2002. The total amount outstanding at February 28, 2002 was $89 million.

The Company expects to continue to utilize cash from operations as well as its available funds under its revolving credit facility to fund capital expenditures and working capital obligations during 2002. As of February 28, 2002, the Company had $111 million available under its line of credit. Future cash flows will be influenced, among other factors, by the market price of natural gas as well as the number of producing properties on line. To the extent that gas prices decline, the Company's revenues, cash flows and earnings would be adversely affected, which would require the Company to rely more heavily on its revolving credit facility to fund its 2002 capital budget. The Company's management believes that if gas prices were to decline to a level that would have a material adverse effect on cash flows, the Company would continue to meet its working capital obligations and its 2002 capital budget (as discussed below) through its capacity on the revolving credit facility. If natural gas prices drop significantly for an extended period of time, management may reduce the anticipated capital expenditure budget for 2002.

The Company's 2002 capital budget is estimated to be approximately $106.1 million. Of this total, approximately $87.4 million will be directed to Evergreen's coal bed methane operations in the Raton Basin, which includes approximately $31.6 million for infrastructure, approximately $37.7 million for the drilling and completion of 152 wells, and $18.1 million primarily for recompletions and equipment. Approximately $10 million of the 2002 capital budget is expected to be spent on the Company's coal bed methane project in the United Kingdom and tight gas sand project in Northern Ireland and the Republic of Ireland, and the remaining $8.7 million largely will be used for domestic exploration projects.

2001 and 2000 Cash Flows and Capital Expenditures

Cash flows provided by operating activities were $90,113,000 for the year ended December 31, 2001 as compared to cash flows provided by operating activities of $31,274,000 for the year ended December 31, 2000. The increase of $58,839,000, or 188%, was primarily attributable to a 127% increase in net income along with a proportionate increase in the non-cash expenses of depreciation, depletion and amortization and deferred income taxes.

Cash flows used in investing activities were $122,547,000 during the year ended December 31, 2001, versus $144,196,000 in 2000. The decrease of $21,649,000 was primarily attributable to a decrease in cash used in acquisitions from approximately $70 million last year to approximately $20 million in 2001. This decrease of $50 million was offset by additional cash used in an accelerated drilling program in 2001 of 145 wells in the Raton Basin compared to 105 wells drilled in the prior year.

Total capital expenditures for the year ending December 31, 2001 were $126.1 million. These capital costs included: $23 million for the June 2001 property acquisition (which includes $2.5 million in post-acquisition development costs); $37.8 million to drill and complete 145 Raton Basin gas wells (the 2001 drilling program) and the completion of 32 wells drilled in 2000; $30.4 million for the Raton Basin gas collection system; $7.1 million related to other Raton Basin development costs; $4.7 million for domestic exploration projects; and $13.9 million for international exploration projects. The remaining amount of approximately $9.2 million consisted primarily of capital expenditures by the Company's wholly owned well service company, which included the purchase of a coiled tubing unit, two workover rigs and deposits on a second fleet of fracture stimulation and cementing units.

Cash flows provided by financing activities were $31,457,000 during the year ended December 31, 2001, as compared to cash flows provided by financing activities of $116,269,000 in 2000. The significant

decrease was due to reduced net borrowings resulting from the increase in operating cash flows of $59 million and a decrease in cash used in investing activities of $22 million. In December 2001 the Company issued $100 million in convertible notes. See Note 5 to the Consolidated Financial Statements. The $97 million in net proceeds from the issuance of the notes were used to pay down the Company's revolving credit facility.

Contractual Obligations

In addition to the revolving credit facility and senior convertible notes discussed above, the Company had various other contractual obligations as of December 31, 2001. The following table lists the Company's significant liabilities at December 31, 2001 including the revolving credit facility and the senior convertible notes:

	Payments Due By Period				
Contractual Obligations	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**	**Total**

	Payments Due By Period (In Thousands)				
Revolving credit facility	$	$ 81,000	$	$	$ 81,000
Senior convertible notes			100,000		100,000
Operating leases	2,288	1,984	1,300	889	6,461
Transportation commitments	10,779	25,791	25,808	71,982	134,360
Unconditional purchase obligations	10,500				10,500
Drilling/Work commitments	4,700				4,700
Total contractual cash obligations	$ 28,267	$ 108,775	$ 127,108	$ 72,871	$ 337,021

The Company leases its corporate offices in Denver, Colorado under the terms of an operating lease, which expires in 2008. Yearly payments under the lease are approximately $620,000. The remaining operating lease commitments represent vehicle leases, which expire during 2002 through 2004. The Company anticipates it will continue to utilize operating leases for its vehicle needs in the future.

Evergreen's current firm transportation commitments with CIG are 97 MMcf of gross gas sales per day. The Company has committed to an additional 30 MMcf per day, subject to a ramp-up schedule which anticipates 5 MMcf per day increments each four months from June 2002 through February 2004. Thus, Evergreen's total transportation commitments will increase in increments to a total of 127 MMcf per day by February 2004. If the Company is unable to fulfill its transportation commitments, amounts paid for transportation on up to 41 MMcf per day can be credited toward future transportation costs through August 2006. Under terms of these transportation agreements with CIG, the Company has committed to pay approximately $134 million through 2014.

At December 31, 2001, the Company had entered into agreements with various vendors to construct well service equipment and gas gathering assets at a total cost of approximately $13 million. As of December 31, 2001, approximately $2.5 million was paid as deposits on such equipment, which is included in property and equipment on the Company's consolidated balance sheet. Subsequent to December 31, 2001, the Company committed to purchase two additional compressors at a combined estimated cost of approximately $3.5 million.

The Company currently has a commitment to drill six wells in the Pioneer Unit in Alaska in 2002. Total expected costs related to this commitment are estimated to be approximately $3 million. The Company has also entered into a joint venture agreement with a work commitment covering 29,000 acres of coal bed methane properties in Huerfano County, Colorado, in the northern end of the Raton Basin. Under the agreement, Evergreen will spend $2 million through September 30, 2002 to earn a 50% working interest in the properties, which currently contain 15 shut-in wells. The properties are

located approximately 20 miles north of Evergreen's existing 274,000 acres of coal bed methane properties in Las Animas County, Colorado. Evergreen's planned expenditures will be primarily for drilling, completions, workovers, equipment and fracture stimulations. As of December 31, 2001, the Company had incurred approximately $300,000 toward the $2 million work commitment.

Hedging Transactions

Evergreen's production is generally sold at prevailing market prices. However, the Company periodically enters into hedging transactions for a portion of its production when market conditions are deemed favorable and natural gas prices exceed the Company's minimum internal price targets. See "Item 7A Quantitative and Qualitative Disclosure About Market Risk."

The Company's objective in entering into hedging transactions is to manage price fluctuations and achieve a more predictable cash flow. These transactions limit Evergreen's exposure to declines in prices, but also limit the benefits Evergreen would realize if prices increase. As of December 31, 2001, the Company had entered into the following contracts to sell its gas production (the Company's hedging contracts are denoted in MMBtu, which convert on an approximately 1-for-1 basis into Mcf):

- a maximum of 4 MMcf per day from January 1, 2001 through April 30, 2003, at a price of $2.40 per Mcf plus transportation costs, and

10 MMcf per day from January 1, 2001 through March 31, 2003 for the lesser of then current market price or a gross price of $2.45 per Mcf.

In consideration for the extension of the $2.45 contract, Evergreen received $1,762,000 over the 12-month period ended October 31, 2000, which is being amortized over the contract term. As of December 31, 2001, $565,000 was recognized as deferred revenue and will be recognized as revenue in future periods.

The Company may use derivative instruments to manage exposure to commodity prices, foreign currency and interest rate risks. The Company's objectives for holding derivatives are to minimize risks using the most effective methods to eliminate or reduce the impacts of these exposures.

The Company occasionally enters into fixed-price physical delivery contracts as discussed above as well as commodity price swap derivatives to manage price risk with regard to a portion of its natural gas production. Commodity price swap derivative contracts are designated as cash flow hedges. As a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in Other Comprehensive Income ("OCI") and are recognized in the statement of income when the associated production occurs and the resulting cash flows are reported as cash flows from operations. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings. To qualify as a cash flow hedge, these swap contracts must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price of anticipated future production such that the Company's exposure to the effects of commodity price changes is reduced.

During the year ended December 31, 2001, the Company had two commodity price swap agreements. One contract was for 10 MMcf per day from January 1, 2001 through December 31, 2001 at a hedge price of $6.10 per Mcf and the other contract was for 10 MMcf per day from February 1, 2001 through December 31, 2001 at a hedge price of $6.43 per Mcf. The contracts called for the Company to receive or make payments based upon the differential between the hedge price and the market gas price, as defined in the contracts, for the notional quantity. During the year ended December 31, 2001, the Company realized $13.9 million in gains on the two commodity swaps which have been included in natural gas revenues for the year ended December 31, 2001. At December 31, 2001, the Company had no financial hedges in place related to its natural gas production.

In February 2002, the Company entered into the following commodity swap agreements (the swaps are denoted in MMBtu, which convert on an approximate 1-for-1 basis into Mcf):

Duration	**Volume (Mcf) Per Day**	**Price Per Mcf**
March 2002 - June 2002	20,000	$ 2.315
March 2002 - June 2002	20,000	$ 2.325
March 2002 - June 2002	10,000	$ 2.380
March 2002 - June 2002	5,000	$ 2.300
April 2002 - June 2002	5,000	$ 2.300

In April 2001, the Company entered into an interest rate swap designated as a cash flow hedge. The swap allows for strategies designed to protect against fluctuations. The swap exchanges a series of future cash payments, one on a fixed-rate basis and the other on a floating rate-basis, to lock in a specific interest rate that is received by the Company. The interest rate swap has a notional amount of $25 million at a LIBO rate of 4.4% and is effective April 23, 2001 through April 23, 2002. At December 31, 2001, the unrealized loss for this contract was approximately $129,000 net of taxes of $75,000. The Company recognized a $233,000 loss on this contract during the year ended December 31, 2001, which was included in interest expense for the period.

Income Taxes and Net Operating Losses

The Company has net operating loss carryforwards for tax purposes of approximately $14,800,000, which expire beginning in 2010 through 2018. Additionally, the Company has tax credit carryforwards for tax purposes of approximately $5,609,000, $5,421,000 of which relate to state tax credits and will expire beginning in 2002 through 2013.

The state tax credits are subject to limitation and the Company has concluded that, based upon expected future results, the future reversals of taxable temporary differences and the tax benefits derived from the exercise of non-qualified employee stock options, there is no reasonable assurance that the entire tax benefit of the tax credits can be used. Accordingly, a valuation allowance has been established. Because of the reduction in natural gas prices, the increased drilling program and the related intangible drilling costs and the utilization of the net operating losses, the Company estimates that cash payments for taxes will not be required until 2003.

Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations." SFAS No. 141 is intended to improve the transparency of the accounting and reporting for business combinations by requiring that all business combinations be accounted for under a single method the purchase method. This statement is effective for all business combinations initiated after June 30, 2001.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement applies to intangibles and goodwill acquired after June 30, 2001, as well as goodwill and intangibles previously acquired. Under this statement, goodwill as well as other intangibles determined to have an infinite life will no longer be amortized; however, these assets will be reviewed for impairment on a periodic basis. This statement is effective for the Company for the first quarter in the fiscal year ending December 31, 2002. Management does not believe that the adoption of this statement will have a material effect on the Company's financial statements.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in

the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Management has not yet determined the impact of the adoption of this statement.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally, is to be applied prospectively. Management has not yet determined the impact of the adoption of this statement.

Critical Accounting Policies and Estimates

The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its Consolidated Financial Statements.

Reserve Estimates: The Company's estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material.

Many factors will affect actual future net cash flows, including:

- the amount and timing of actual production;

supply and demand for natural gas;

curtailments or increases in consumption by natural gas purchasers; and

changes in governmental regulations or taxation.

Property, Equipment and Depreciation: The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and

properties under development are also capitalized to oil and gas properties. If the net investment in oil and gas properties exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from proved reserves (see Note 15 to the Consolidated Financial Statements), and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

Gas collection and support equipment is stated at cost. Depreciation and amortization for the Raton Basin gas collection system, with the exception of the gas compressor facilities, is computed on the units-of-production method based upon total reserves of the field. Gas compressor facilities and other support equipment are depreciated using the straight-line method over the estimated useful lives of the assets of 3 to 30 years.

The Company applies SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of." Under SFAS No. 121, long-lived assets and certain intangibles are reported at the lower of the carrying amount or their estimated recoverable amounts. Long-lived assets subject to the requirements of SFAS No. 121 are evaluated for possible impairment through review of undiscounted expected future cash flows. If the sum of undiscounted expected future cash flows is less than the carrying amount of the asset or if changes in facts and circumstances indicate, an impairment loss is recognized.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Company measures its exposure to market risk at any point in time by comparing its open positions to a market risk of fair value. The market prices the Company uses to determine fair value are based on management's best estimates, which consider various factors including closing exchange prices, volatility factors and the time value of money. At December 31, 2001, the Company was exposed to some market risk with respect to long-term debt, foreign currency and natural gas prices; however, management did not believe such risk to be material.

Commodity Risk. The Company's major market risk exposure is in the pricing applicable to its gas production. Realized pricing is primarily driven by the prevailing price for crude oil and spot prices applicable to Evergreen's United States natural gas production. Historically, prices received for gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Gas price realizations ranged from a monthly low of $1.24 per Mcf to a monthly high of $10.02 per Mcf during 2001.

The Company periodically enters into hedging activities on a portion of its projected natural gas production through a variety of financial and physical arrangements intended to support natural gas prices at targeted levels and to manage its exposure to gas price fluctuations. Evergreen may use futures contracts, swaps, options and fixed-price physical delivery contracts to hedge its commodity prices. As discussed above, the Company had two fixed-price physical delivery contracts and no financial hedges in place at December 31, 2001.

Assuming total gas production and the percentage of gas production hedged under physical delivery contracts remain at December 2001 levels, a 10% decrease in the average unhedged natural gas prices realized during the year would reduce the Company's natural gas revenues by approximately $11 million on an annual basis.

Interest Rate Risk. At December 31, 2001, Evergreen had long-term debt outstanding of $181 million. The interest rates on the Company's revolving credit facility range from LIBOR plus 1.5% to prime plus 0.25% and are variable; however, they may be fixed at Evergreen's option for periods of time between 30 to 90 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding at the end of 2001 would equal approximately 35 basis points. Such an increase in interest rates would impact Evergreen's 2002 interest expense by approximately $283,500, assuming borrowed amounts under the credit facility remained at $81 million.

The $100 million in convertible notes the Company issued in December 2001 have a fixed interest rate of 4.75%; however, as discussed in Note 5 to the Consolidated Financial Statements, up to an additional 0.40% may be paid as contingent interest if certain conditions are met. Accordingly, the Company's annual interest payment on the $100 million convertible notes will be a minimum of $4.75 million and a maximum of $5.15 million.

Foreign Currency Risk. In 2001, the Company drilled six tight gas sands wells in Northern Ireland and the Republic of Ireland. In 2002, the Company plans on drilling approximately 10 to 12 wells in Northern Ireland, the Republic of Ireland and in the United Kingdom at a total estimated cost of $10 million. The Company's assets, revenue and expense accounts relating to these projects are based on the U.S. dollar equivalent of such amounts measured in the British pound sterling and the Euro. The assets and liabilities of these projects are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow will be translated using the average exchange rate for the reporting period. Any significant change in the exchange rate for the pound sterling and/or Euro would have an impact on the cost of these drilling programs.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

Not Applicable.

PART III

The information required by Part III of Form 10-K is incorporated herein by reference to Registrant's definitive Proxy Statement to be filed in connection with the Annual Meeting of Shareholders to be held May 7, 2002.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)

(1) See Index to Consolidated Financial Statements at Item 8.

(a)

(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Consolidated Financial Statements.

(a)

(3) Exhibits:

3.1 Articles of Incorporation as amended: Incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1, Commission File No. 33-273035, by reference to Exhibit I to the Company's Current Report on Form 8-K dated December 9, 1994 and by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed June 8, 1998.

3.2 Articles of Amendment to Articles of Incorporation stating terms of redeemable preferred stock: Incorporated by reference to Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2000.

3.3 Bylaws: Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed June 8, 1998.

4.1 Shareholders' Rights Agreement: Incorporated by reference to Exhibit 2 to the Company's Current Report on Form 8-K dated July 7, 1997. 4.2

4.2 Form of Global Note for 4.75% Senior Convertible Notes due December 15, 2021 (included in Exhibit 4.3)

4.3 Indenture, dated December 18, 2001

4.4 Registration Rights Agreement, dated December 18, 2001

10.1 Amended and Restated Credit Agreement by and among Evergreen Resources, Inc. and Hibernia National Bank, BNP Paribas, Wells Fargo Bank Texas, NA, BankOne, NA, Fleet National Bank, Bank of Scotland, and First Union National Bank dated August 15, 2000, as amended September 15, 2000 and November 15, 2000: Incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2000.

10.2 Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate

Gas Company and Primero Gas Marketing Company, Dated August 22, 1997: Incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-3 filed on November 21, 1997, Commission File No. 333-40817.

10.3 Deeds of Variation between The Secretary of State for Trade and Industry and Evergreen Resources (UK) Limited dated January 9, 1997: Incorporated by reference to Exhibit 10.6 of the Company's Registration Statement on Form S-3 filed on November 21, 1997, Commission File No. 333-40817.

10.4 Evergreen Resources, Inc. Initial Stock Option Plan: Incorporated by reference to the exhibit accompanying the Company's Definitive Proxy Statement on Schedule 14A filed on April 20, 1998 (Compensatory plan or arrangement).

10.5 Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate Gas Company and Consolidated Industrial Services, Inc., dated March 20, 1997: Incorporated by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998.

10.6 Firm Transportation Service Agreement Rate Schedule TF-1 between Colorado Interstate Gas Company and Amoco Energy Trading corporation, dated November 1, 1997: Incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 1998.

10.7 2000 Stock Incentive Plan of Evergreen Resources, Inc.: Incorporated by reference to Exhibit A to the Company's definitive proxy materials on Schedule 14A filed on May 1, 2000 (Compensatory plan or arrangement).

10.8 Agreement for Purchase and Sale dated September 19, 2000, by and between Apache Canyon Gas, L.L.C., as Seller and Evergreen Resources, Inc. as Buyer: Incorporated by reference to Exhibit 2.1 to the Company's Form 8-K filed on October 5, 2000.

10.9 Agreement for Purchase and Sale dated September 19, 2000, by and between Apache Canyon Gas, L.L.C., as Seller and Evergreen Resources, Inc. as Buyer: Incorporated by reference to Exhibit 2.2 to the Company's Form 8-K filed on October 5, 2000.

21.0 Subsidiaries of registrant: Incorporated by reference to Note 1 of the Notes to Consolidated Financial Statements included herein.

22.0 Reserve Audit Report prepared by Netherland Sewell & Associates, Inc.

23.0 Consent of Independent Certified Public Accountants.

24.1 Power of Attorney: contained on signature page.

(b)

Reports on Form 8-K.

On December 11, 2001, the Company filed a Current Report on Form 8-K to disclose that on December 10, 2001, it announced that it intended to offer, subject to market and other conditions, $100 million of Senior Convertible Notes due 2021 (plus an additional amount of up to $25 million at the option of the initial purchaser) to qualified institutional buyers under Rule 144A of the Securities Act of 1933, as amended.

On December 17, 2001, the Company filed a Current Report on Form 8-K to disclose that on December 13, 2001, it announced that it had sold $100 million of senior convertible notes to qualified institutional investors in a private placement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EVERGREEN RESOURCES, INC.

Date: March 1, 2002

By: /s/ MARK S. SEXTON

Mark S. Sexton
President and Chief Executive Officer
(Principal Executive Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Mark S. Sexton and Kevin R. Collins, and each of them, as true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all which said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Date: March 1, 2002	/s/ MARK S. SEXTON Mark S. Sexton President, Chief Executive Officer and Director (Principal Executive Officer)
Date: March 1, 2002	/s/ KEVIN R. COLLINS Kevin R. Collins, Vice President Finance CFO and Treasurer (Principal Financial and Accounting Officer)
Date: March 1, 2002	/s/ ALAIN BLANCHARD Alain Blanchard, Director
Date: March 1, 2002	/s/ DENNIS R. CARLTON Dennis R. Carlton, Director

Date: March 1, 2002 /s/ LARRY D. ESTRIDGE

	Larry D. Estridge, Director
Date: March 1, 2002	/s/ JOHN J. RYAN III
	John J. Ryan III, Director
Date: March 1, 2002	/s/ SCOTT D. SHEFFIELD
	Scott D. Sheffield, Director
Date: March 1, 2002	/s/ ARTHUR L. SMITH
	Arthur L. Smith, Director

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Report of Independent Certified Public Accountants

To the Stockholders and Board of Directors
Evergreen Resources, Inc.
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Evergreen Resources, Inc. and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity, cash flows, and comprehensive income for each of the three years in the period ended December 31, 2001. 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Evergreen Resources, Inc. and subsidiaries at December 31, 2001 and 2000 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method for recording derivative instruments.

BDO SEIDMAN, LLP

Denver, Colorado
February 15, 2002

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Evergreen Resources, Inc.

Consolidated Balance Sheets

December 31,

	2001	2000
	(In Thousands)	
ASSETS		
Current:		
Cash and cash equivalents	$ 3,024	$ 4,034
Accounts receivable (Notes 2 and 10)	10,119	15,194
Other current assets	1,455	1,156
Total current assets	14,598	20,384
Property and equipment, at cost (Notes 1, 3, 4 and 15): based on the full cost method of accounting for oil and gas properties	584,150	446,001
Less accumulated depreciation, depletion and amortization	51,561	34,052
Net property and equipment	532,589	411,949
Designated cash (Note 1)		2,376
Other assets (Notes 1 and 13)	8,838	16,036
	$ 556,025	$ 450,745
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 7,355	$ 5,408
Amounts payable to oil and gas property owners (Note 1)	4,080	3,183
Accrued expenses and other	9,956	4,943
Total current liabilities	21,391	13,534
Notes payable (Note 4)	81,000	149,748
Senior convertible notes (Note 5)	100,000	
Deferred income taxes (Note 6)	34,702	17,218
Production taxes payable	2,722	2,376
Deferred revenue (Note 12)	565	1,017
Total liabilities	240,380	183,893
Minority interest in subsidiary (Note 1)	705	
Commitments and contingencies (Notes 3, 4, 5 and 12)		
Stockholders' equity (Notes 3, 7, 8 and 9):		
Preferred stock, $1.00 par value; shares authorized, 24,900; none outstanding		
Common stock, $.01 stated value; shares authorized, 50,000; shares issued and outstanding 18,847 and 18,328	188	183
Additional paid-in capital	256,978	247,377
Retained earnings	58,795	20,268
Accumulated other comprehensive loss	(1,021)	(976)
Total stockholders' equity	314,940	266,852

	December 31,	
	$ 556,025	$ 450,745

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Income

	Years Ended December 31,		
	2001	**2000**	**1999**
	(In Thousands, Except Per Share Data)		
Revenues:			
Natural gas revenues (Note 10)	$ 119,745	$ 59,128	$ 26,722
Interest and other	1,025	565	207
Total revenues	120,770	59,693	26,929
Expenses:			
Lease operating expense	12,228	7,475	4,245
Transportation costs	9,524	5,902	4,001
Production and property taxes	5,472	2,567	1,146
Depreciation, depletion and amortization	16,212	8,190	4,757
General and administrative expenses	6,985	4,364	3,024
Interest expense	8,331	3,330	1,927
Other	653	178	175
Total expenses	59,405	32,006	19,275
Income from continuing operations before income taxes	61,365	27,687	7,654
Income tax provision deferred (Note 6)	22,838	10,695	2,979
Income from continuing operations	38,527	16,992	4,675
Discontinued operations (Note 14)			
Gain on disposal of discontinued operations, net			452
Net income	38,527	16,992	5,127
Preferred stock dividends (Notes 7 and 8)		(2,929)	
Net income attributable to common stockholders	$ 38,527	$ 14,063	$ 5,127
Basic income per common share (Note 8):			
From continuing operations	$ 2.08	$ 0.91	$ 0.36

	Years Ended December 31,		
From discontinued operations			0.03
Basic income per common share	$ 2.08	$ 0.91	$ 0.39
Diluted income per common share (Note 8):			
From continuing operations	$ 1.98	$ 0.87	$ 0.34
From discontinued operations			0.03
Diluted income per common share	$ 1.98	$ 0.87	$ 0.37

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 2001, 2000 and 1999

	Common Stock $.01 Stated Value		Additional Paid-In Capital	Retained Earnings	Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount				
				(In Thousands)		
Balance, January 1, 1999	11,143	$ 111	$ 78,380	$ 1,078	$ 110	$ 79,679
Issuance of common stock for services (Note 8)	51	1	800			801
Exercise of stock options and purchase warrants, net (Note 9)	188	2	1,361			1,363
Issuance of common stock for property interests (Note 8)	56	1	920			921
Issuance of common stock for subsidiary (Notes 3 and 8)	120	1	2,499			2,500
Issuance of common stock pursuant to public offering (Note 8)	3,163	31	65,041			65,072
Common stock repurchase (Note 8)	(100)	(1)	(1,708)			(1,709)
Issuance of warrants			33			33
Other comprehensive loss					(277)	(277)
Net income				5,127		5,127
Balance, December 31, 1999	14,621	146	147,326	6,205	(167)	153,510
Issuance of common stock for services (Note 8)	27		722			722
Exercise of stock options and purchase warrants, net (Note 9)	44	1	323			324
Issuance of common stock for property interests (Note 8)	512	5	11,573			11,578
Issuance of common stock pursuant to public offering (Note 8)	3,008	30	83,434			83,464

	Common Stock $.01 Stated Value					
Stock to be issued for property acquisition (Notes 3 and 8)		1	3,999			4,000
Other comprehensive loss	116				(809)	(809)
Preferred stock dividends				(2,929)		(2,929)
Net income				16,992		16,992
Balance, December 31, 2000	18,328	183	247,377	20,268	(976)	266,852
Issuance of common stock for services (Note 8)	30		898			898
Exercise of stock options and purchase warrants, net (Note 9)	503	5	3,956			3,961
Common stock exchanged as payment for exercise of stock purchase options (Note 9)	(44)		(1,653)			(1,653)
Tax benefit from exercise of non-qualified stock options and warrants			5,534			5,534
Issuance of common stock for property interests (Note 8)	40	1	1,219			1,220
Common stock repurchase (Note 8)	(10)	(1)	(353)			(354)
Other comprehensive loss					(45)	(45)
Net income				38,527		38,527
Balance, December 31, 2001	18,847	$ 188	$ 256,978	$ 58,795	$ (1,021)	$ 314,940

See accompanying Notes to Consolidated Financial Statements.

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Evergreen Resources, Inc.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2001	**2000**	**1999**
	(In Thousands)		
Increase (Decrease) in Cash and Cash Equivalents			
Operating activities:			
Net income	$ 38,527	$ 16,992	$ 5,127
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	16,212	8,190	4,757
Deferred income taxes	22,838	10,655	2,979
Gain on disposal of discontinued operations, net			(452)
Non-cash compensation	103	152	545
Other	376	300	170
Changes in operating assets and liabilities:			
Accounts receivable	5,370	(10,191)	(293)
Other current assets	(443)	(476)	(527)
Change in designated cash	2,376	(63)	468

	Years Ended December 31,		
Accounts payable	(141)	2,035	(187)
Non-current production taxes payable	191	63	(468)
Accrued expenses and other	5,156	2,600	612
Deferred revenue	(452)	1,017	
Net cash provided by operating activities	90,113	31,274	12,731
Investing activities:			
Investment in property and equipment	(120,681)	(130,101)	(43,243)
Investment in affiliated company (Note 13)	(1,515)		
Purchase of subsidiary (Note 3)			(2,500)
Proceeds from sale of investment (Note 14)			2,258
Change in other assets	(351)	(14,095)	(379)
Net cash used in investing activities	(122,547)	(144,196)	(43,864)
Financing activities:			
Net (payments on) proceeds from notes payable	(68,748)	134,248	(28,639)
Proceeds from senior convertible notes	100,000		
Redemption of preferred stock		(100,000)	
Principal payments on capital lease obligations			(4,029)
Proceeds from issuance of common stock, net	2,308	83,788	66,448
Common stock repurchase	(354)		(1,709)
Dividends paid on preferred stock		(2,929)	
Debt issue costs	(3,241)	(597)	(77)
Change in cash held from operating oil and gas properties	1,492	1,759	(1,523)
Net cash provided by financing activities	31,457	116,269	30,471
Effect of exchange rate changes on cash	(33)	36	(21)
Increase (decrease) in cash and cash equivalents	(1,010)	3,383	(683)
Cash and cash equivalents, beginning of year	4,034	651	1,334
Cash and cash equivalents, end of year	$ 3,024	$ 4,034	$ 651

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2001	**2000**	**1999**

	Years Ended December 31,		
	(In Thousands)		
Net income	$ 38,527	$ 16,992	$ 5,127
Cumulative effect of change in accounting principle, net of tax of $273	(446)		
Derivative instruments:			
Unrealized gain on commodity price swaps	14,614		
Unrealized loss on interest rate swap	(437)		
Reclassification adjustment to income	(13,895)		
Reclassification adjustment to expense	233		
Derivative instruments, before taxes	515		
Related income tax effect	(198)		
Derivative instruments, net of tax	317		
Available for sale instruments:			
Unrealized gain	1,046		
Related income tax effect	(389)		
Available for sale instruments, net of tax	657		
Foreign currency translation adjustments	(573)	(809)	(277)
Comprehensive income	$ 38,482	$ 16,183	$ 4,850

See accompanying Notes to Consolidated Financial Statements.

Evergreen Resources, Inc.

Notes to Consolidated Financial Statements

Years Ended December 31, 2001, 2000 and 1999

(1) SUMMARY OF ACCOUNTING POLICIES

Business

Evergreen Resources, Inc. ("Evergreen" or the "Company") is an independent energy company engaged in the operation, development, production, exploration and acquisition of natural gas properties. Evergreen is one of the leading developers of coal bed methane reserves in the United States. Its current operations are principally focused on developing and expanding its coal bed methane project located in the Raton Basin in southern Colorado. The Company has begun coal bed methane projects in the United Kingdom and Alaska. In addition, the Company is engaged in the exploration of natural gas prospects in Northern Ireland and the Republic of Ireland and owns additional interests in other domestic and international areas.

Consolidation

The financial statements include the accounts of Evergreen and its wholly-owned subsidiaries, Evergreen Operating Corporation ("EOC"), Evergreen Resources (UK) Ltd. ("ERUK"), Powerbridge, Inc., Evergreen Well Service Company, Primero Gas Marketing Company ("PGMC"), Primero Gas Company, LLC, XYZ Minerals, Inc. ("XYZ"), Evergreen Resources (Alaska) Corporation, Long Canyon Gas Company, LLC ("LC"), Evergreen Supply and Distribution Company ("ESD"), and its majority owned subsidiary Lorencito Gas Gathering Company, LLC ("LGG"). ERUK is organized under the laws of the United Kingdom and XYZ is a Delaware corporation. The other subsidiaries are all organized under the laws of Colorado. PGMC owns an 85% interest in LGG. All significant intercompany balances and transactions have been eliminated in consolidation.

The Company also has a 40% ownership in Argos Evergreen Limited, a Falkland Islands company, which owns offshore drilling rights in the North Falklands basin. This investment is accounted for by the equity method of accounting.

Uses of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the Unites States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve volumes and the related present value of estimated future net cash flows. See Note 15 for unaudited supplemental oil and gas information.

Property and Equipment

The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, including salaries, benefits and other internal salary related costs directly attributable to these activities. Evergreen capitalized $4,548,000, $2,786,000, and $1,845,000 of internal costs for the years ended December 31, 2001, 2000 and 1999. Costs associated with production and general corporate activities

are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and gas properties. If the net investment in oil and gas properties exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from proved reserves (see Note 15) and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized.

Depreciation and depletion of proved oil and gas properties is computed on the units-of-production method based upon estimates of proved reserves with oil and gas being converted to a common unit of measure based on their relative energy content. Unproved oil and gas properties, including any related capitalized interest expense, are not amortized, but are assessed for impairment either individually or on an aggregated basis.

The costs of certain unevaluated leasehold acreage, wells drilled and international concession rights are not being amortized. Costs not being amortized are periodically assessed for possible impairments or reductions in value. If a reduction in value has occurred, costs being amortized are increased or a charge is made against earnings for those international operations where a reserve base is not yet established.

Gas collection and support equipment are stated at cost. Depreciation and amortization for the Raton Basin gas collection system, with the exception of the gas compressor facilities, is computed on the units-of-production method based upon total reserves of the field. Gas compressor facilities and other support equipment are depreciated using the straight-line method over the estimated useful lives of the assets of 3 to 30 years.

The Company applies Statement of Financial Accounting Standards ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of." Under SFAS No. 121, long-lived assets and certain intangibles are reported at the lower of the carrying amount or their estimated recoverable amounts. Long-lived assets subject to the requirements of SFAS No. 121 are evaluated for possible impairment through review of undiscounted expected future cash flows. If the sum of undiscounted expected future cash flows is less than the carrying amount of the asset or if changes in facts and circumstances indicate, an impairment loss is recognized. No impairment existed at December 31, 2001.

Amounts Payable to Oil and Gas Property Owners

Amounts payable to oil and gas property represents production revenue that the Company, as operator, is collecting and distributing to revenue interest owners.

Minority Interest

The minority interest of $705,000 on the Company's consolidated balance sheet at December 31, 2001 represents the 15% outside ownership in LGG. The minority interest in LGG's net income was approximately $2,500 during the year ended December 31, 2001 and is included in other expense in the Company's consolidated statement of income.

Designated Cash

Through September 30, 2001, the Company recorded designated cash equal to the production taxes its operating company, EOC, had withheld from Evergreen and outside working interest owners and royalty owners. Effective in the fourth quarter of 2001, the Company maintains a separate cash account with a balance equal only to the non-current production taxes EOC has withheld from revenue owners outside the consolidated companies.

Income Taxes

The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences. Accordingly, deferred tax liabilities and assets are determined based on the temporary differences between the financial statement and tax bases of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse.

Environmental Matters

Environmental costs are expensed or capitalized depending on their future economic benefit. Costs that relate to an existing condition caused by past operations with no future economic benefit are expensed. Liabilities for future expenditures of a non-capital nature are recorded when future environmental expenditures and/or remediation is deemed probable and the costs can be reasonably estimated. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Net Income Per Share

The Company applies SFAS No. 128, "Earnings Per Share" for the calculation of "Basic" and "Diluted" earnings per share. Basic earnings per share includes no dilution and is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution of securities that could share in the earnings of the Company.

Cash Equivalents

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

Revenue Recognition

Natural gas sales revenues generally are recorded using the sales method, whereby the Company recognizes sales revenue based on the amount of gas sold to purchasers on its behalf.

The Company has received cash payments from a purchaser in consideration for a contract to sell certain future production. These cash payments were initially recorded as deferred revenue and are amortized as revenue pro-rata over the contract term.

Transportation Costs

The Company accounts for transportation costs under Emerging Issues Task Force ("EITF") 00-10, "Accounting for Shipping and Handling Fees and Costs," whereby amounts paid for transportation costs are classified as operating expense and not netted against natural gas revenues.

Debt Issue Cost

The Company had approximately $4.7 million and $1.3 million of debt issue costs at December 31, 2001 and 2000, respectively, net of accumulated amortization of $942,000 and $671,000, respectively, which are included in other assets in the Company's consolidated balance sheet. The debt issue costs are being amortized over the term of the associated long-term debt.

Comprehensive Income

The Company has elected to report comprehensive income in a consolidated statement of comprehensive income. Comprehensive income is composed of net income and all changes to stockholders' equity, except those due to investments by stockholders, changes in paid-in capital and distributions to stockholders. The following table identifies the components of other comprehensive loss for each of the periods presented:

	December 31,		
	2001	2000	1999
Accumulated foreign currency translation	$ (1,549)	$ (976)	$ (167)
Unrealized loss on interest rate swap, net of tax	(129)		
Unrealized gain on investment, net of tax	657		
	$ (1,021)	$ (976)	$ (167)

Stock Options

The Company applies APB Opinion 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for all stock option plans. Under APB Opinion 25, compensation cost has been recognized for stock options granted in situations where the option price is less than the market price of the underlying common stock on the date of grant.

SFAS No. 123, "Accounting for Stock-Based Compensation," requires the Company to provide pro forma information regarding net income as if compensation cost for the Company's stock option plans had been determined in accordance with the fair value based method prescribed in SFAS No. 123. To provide the required pro forma information, the Company estimates the fair value of each stock option at the grant date by using the Black-Scholes option-pricing model.

Foreign Currency Translation

The functional currency for the Company's foreign operations is the applicable foreign currency. The translation of the applicable foreign currency into U.S. dollars is performed for balance sheet accounts using current exchange rates in effect at the balance sheet date and for revenue and expense accounts using a weighted average exchange rate during the period. The gains or losses resulting from

such translation are included in the consolidated statements of stockholders' equity and comprehensive income.

Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2001 and 2000.

December 31,

	2001		2000	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(In Thousands)			
Cash and cash equivalents	$ 3,024	$ 3,024	$ 4,034	$ 4,034
Investment in common stock in unaffiliated company	2,476	2,476	1,080	1,840
Investment in KFx (Note 13)	1,949	2,000		
Commodity swap				(719)
Interest rate swap	(204)	(204)		
Notes payable	(81,000)	(81,000)	(149,748)	(149,748)
Senior convertible notes	(100,000)	(100,000)		

The following methods and assumptions were used to estimate the fair value of the financial instruments summarized in the table above. The carrying values of accounts receivable, other assets, accounts payable and accrued expenses included in the accompanying consolidated balance sheets approximated market fair value at December 31, 2001 and 2000.

Cash and cash equivalents

The carrying amounts approximate fair value due to the short-term maturity of the instruments.

Investments

The fair value of the investment in the common stock of an unaffiliated company is based on the quoted market price of such common stock. The fair value of the investment in KFx is based on the anticipated cash flows, which approximates the carrying value.

Interest rate and commodity swaps

The fair values of the swaps were based on expected future cash flows over the remaining life of the swaps discounted at the Company's effective borrowing rate. See "Hedging Activities" for more information on hedging activities.

Debt

The carrying amount of notes payable approximated fair value because the interest rate on the notes payable is variable. The carrying amount of the senior convertible notes at December 31, 2001

approximates fair value as the notes were issued on December 18, 2001 and interest rates remained generally unchanged from December 18, 2001 to December 31, 2001.

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents. The Company's cash equivalents are cash investment funds which are placed with a major financial institution.

The Company manages and controls market and credit risk through established formal internal control procedures, which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to purchasers of the Company's natural gas through formal credit policies, monitoring procedures and letters of credit. See Note 10 for concentrations of accounts receivable at December 31, 2001.

Hedging Activities

Effective January 1, 2001, Evergreen adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Under SFAS No. 133, all derivative instruments, whether designated as hedging relationships or not, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income ("OCI") and are recognized in the income statement when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings.

The adoption of SFAS No. 133 resulted in an after-tax reduction to OCI of $446,000 as a cumulative effect of change in accounting principle. The reduction to OCI at January 1, 2001 was attributable to the commodity price swap agreement designated as a cash flow hedge discussed below for 10 MMcf per day at a hedge price of $6.10 per Mcf. The derivative loss included in OCI as of January 1, 2001 has been reclassified into earnings during the year ended December 31, 2001.

The Company sometimes enters into fixed-price physical delivery contracts and commodity price swap derivatives to manage price risk with regard to a portion of its natural gas production. The Company also occasionally enters into interest rate swaps to manage its exposure to interest rate fluctuations. Commodity price swap and interest rate swap derivative contracts are accounted for using cash flow hedge accounting. Under this method, realized gains and losses on qualifying hedges are recognized in gas revenues or interest expense when the associated revenue stream or expense occurs and the resulting cash flows are reported as cash flows from operations. To qualify as a hedge, these swap contracts must be designated as a cash flow hedge and changes in their fair value must correlate with changes in the price of anticipated future production or anticipated interest payments such that the Company's exposure to the effects of commodity price or interest rate changes is reduced. If the contract is not a hedge, changes in the fair value are recorded in the Company's statement of income currently. If a derivative financial instrument, such as the swaps discussed above, are settled before the date of the anticipated transaction, the Company carries forward the accumulated change in value of the contract and includes it in the measurement of the related transaction.

During the year ended December 31, 2001, the Company had two commodity price swap agreements. One contract was for 10 MMcf per day from January 1, 2001 through December 31, 2001

at a hedge price of $6.10 per Mcf and the other contract was for 10 MMcf per day from February 1, 2001 through December 31, 2001 at a hedge price of $6.43 per Mcf. The contracts called for the Company to receive or make payments based upon the differential between the hedge price and the market gas price, as defined in the contracts, for the notional quantity. During the year ended December 31, 2001, the Company realized $13.9 million in gains on the two commodity swaps which have been included in natural gas revenues in the accompanying consolidated statement of income and in cash provided by operating activities in the accompanying consolidated statement of cash flows. At December 31, 2001, the Company had no financial hedges in place related to its natural gas production.

In April 2001, the Company entered into an interest rate swap designated as a cash flow hedge to manage fluctuations in cash flows resulting from interest rate risk. The swap allows for strategies designed to protect against fluctuations. The swap exchanges a series of future cash payments, one on a fixed-rate basis and the other on a floating-rate basis, to lock in a specific interest rate that is received by the Company. The interest rate swap has a notional amount of $25 million at a LIBO rate of 4.4% and is effective April 23, 2001 through April 23, 2002. At December 31, 2001, the unrealized loss for this contract was approximately $129,000 net of taxes of $75,000, which was estimated based on the expected discounted net cash outflow based on the LIBOR strip at December 31, 2001. During the year ended December 31, 2001, the Company recognized a $233,000 loss on this contract, which was included in interest expense in the accompanying consolidated statements of income and in cash provided by operating activities in the accompanying consolidated statement of cash flows. The Company is exposed to credit risk in the event of nonperformance by the counterparty in the interest rate swap contract; however, the Company does not anticipate nonperformance by the counterparty.

See Note 12 for discussion of commodity swap contracts entered into subsequent to December 31, 2001.

Reclassifications

Certain items included in prior years' financial statements have been reclassified to conform to current year presentation.

Recent Accounting Pronouncements

In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations." SFAS No. 141 is intended to improve the transparency of the accounting and reporting for business combinations by requiring that all business combinations be accounted for under a single method the purchase method. This statement is effective for all business combinations initiated after June 30, 2001.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This statement applies to intangibles and goodwill acquired after June 30, 2001, as well as goodwill and intangibles previously acquired. Under this statement, goodwill as well as other intangibles determined to have an infinite life will no longer be amortized; however, these assets will be reviewed for impairment on a periodic basis. This statement is effective for the Company for the first quarter in the fiscal year ending December 31, 2002. Management does not believe that the adoption of this statement will have a material effect on the Company's financial statements.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires the fair value of a liability for an asset retirement obligation to be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. Management has not yet determined the impact of the adoption of this statement.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS No. 144 is effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally, is to be applied prospectively. Management has not yet determined the impact of the adoption of this statement.

(2) ACCOUNTS RECEIVABLE

The components of accounts receivable include the following:

	December 31,	
	2001	**2000**
	(In Thousands)	
Natural gas sales	$ 7,734	$ 14,078
Joint interest billings and other	1,661	983
Employees	724	133
	$ 10,119	$ 15,194

Accounts receivable from employees are primarily related to payroll taxes due to the Company in conjunction with the employee's exercise of stock purchase options.

(3) PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31,	
	2001	**2000**
	(In Thousands)	
Oil and gas properties:		

	December 31,	
Proved oil and gas properties	$ 376,092	$ 274,978
Unevaluated properties not subject to amortization	56,480	42,410
Accumulated depreciation, depletion and amortization	(38,353)	(25,505)
Net oil and gas properties	394,219	291,883
Gas collection system	121,100	100,602
Construction in progress	3,674	7,857
Support equipment	26,804	20,154
Accumulated depreciation and amortization	(13,208)	(8,547)
Net other property and equipment	138,370	120,066
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 532,589	$ 411,949

Included in construction in progress at December 31, 2001 and December 31, 2000 are costs associated with a new compressor station, gas collection laterals and costs for well equipment. Oil and gas property costs of $56,480,000 and $42,410,000 were not being amortized at December 31, 2001 and December 31, 2000. At December 31, 2001, these costs consisted of $22,150,000 for domestic properties, $22,622,000 for the United Kingdom, $5,203,000 for Northern Ireland, $2,131,000 for the Republic of Ireland, $1,335,000 for the Falkland Islands and $3,039,000 for Chile. The Company will classify the unevaluated costs for the U.K., Northern Ireland, the Republic of Ireland, the Falkland Islands and Chile as evaluated costs when future development of the licenses relating to such properties determines the viability of the underlying reserves. The Company anticipates that substantially all of the unevaluated costs related to domestic properties will be classified as evaluated costs within the next three to five years.

Effective June 1, 2001, the Company purchased an additional 35% ownership interest in LGG and an additional 35% working interest in gas properties located in the Lorencito tract of the Raton Basin (the "Lorencito Property") for approximately $20 million. The Company paid the purchase consideration in July 2001 utilizing $17 million from its revolving credit facility. The acquisition was accounted for under the purchase method of accounting. The purchase price allocation, which was primarily allocated to proved properties and gas collection equipment, is preliminary and will be finalized after management completes its review of the relative fair values of the assets purchased. As a result of the purchase, the Company now owns 85% of LGG and an 80% working interest in the Lorencito properties.

The acquired Lorencito Property interests represented an estimated 40 billion cubic feet of proven net gas reserves at the time of acquisition (an average cost of 50 cents per Mcf). Approximately 63% of the reserves acquired were classified as proved developed with the remaining 37% classified as proved undeveloped. All of the estimated reserves were assigned to the Vermejo and Raton group of coals. The acquisition also included additional interests in an existing compressor station and associated gas collection system. The results of operations of the acquired properties are included in the Company's consolidated statements of income from the effective date of June 1, 2001 through December 31, 2001. The proforma condensed financial results of operations for prior periods have not been presented as the effect on consolidated operations was not material.

Effective September 1, 2000, Evergreen acquired approximately 24,000 gross acres of producing coal bed methane properties in the Raton Basin for approximately $181.5 million. The purchase was accounted for using the purchase method of accounting. The purchase price consideration consisted of approximately $71.5 million in cash ($70 million paid at closing and $1.5 million in post closing adjustments), $100 million in mandatory redeemable preferred stock and $6 million in the Company's common stock paid at closing. In addition to the consideration paid at the closing, on January 5, 2001, the Company delivered 116,009 additional shares of common stock valued at $4 million, under the terms of the acquisition agreement, because the average of the monthly settle prices for the 2001 NYMEX natural gas contracts exceeded $4.465 per MMBtu. The total purchase price was allocated as follows: (1) $166 million to proved oil and gas properties, (2) $2.5 million to the fifty percent ownership interest acquired in LGG, (3) $10.5 million to gas collection equipment, and (4) $3.5 million to unevaluated properties, and $1 million to production and property taxes payable.

In 1997, under a new onshore licensing regime implemented by the U.K. Department of Trade and Industry, Evergreen converted its original licenses to new onshore licenses called Petroleum Exploration and Development Licenses. In connection with such conversion, the Company relinquished rights to approximately 259,000 acres, which were not considered highly prospective for coal bed methane development. Under the licenses, the Company retained approximately 377,000 acres, which were high-graded for coal bed methane and conventional hydrocarbon potential. During 1999, the Company acquired an additional 136,000 acres. During 2000 and 2001, the Company relinquished certain acreage and now has approximately 452,000 acres. The licenses provide up to a 30 year term with optional periodic relinquishment of portions of the license, subject to future development plans. There are no royalties or burdens encumbering these licenses.

The Company is in the process of developing properties in the United Kingdom and is unable to prepare reserve information in this area. The Company experienced delays in its proposed 2001 drilling program throughout 2001 due to the regulatory environment, which included required approvals from local planning commissions for drilling permits, and was consequently unable to complete its anticipated drilling program for 2001. Drilling operations on the first of four planned gob gas wells expected to be drilled in 2002 on Evergreen's United Kingdom coal bed methane acreage began February 5, 2002. The Company expects to obtain planning permission for the remaining three gob gas wells which are expected to be drilled before the end of the second quarter of 2002. Additionally, the Company intends to fracture stimulate three existing mine gas interaction wells in the United Kingdom late in the first quarter or early in the second quarter of 2002.

In March and April 2001, the Company acquired 100% working interest in 1,085,000 acres of prospective tight gas sand properties in Northern Ireland (605,000 acres) and the Republic of Ireland

(480,000 acres) for total consideration of $1,250,000 (23,200 shares of Evergreen common stock valued at $750,000 and $500,000 in cash) plus a small retained net profits interest. Evergreen has drilled four wells in Northern Ireland and two wells in the Republic of Ireland to depths ranging from approximately 2,700 feet to 4,400 feet. Evergreen is in the process of completing five of these six wells. Three wells have been fracture stimulated to date. All five wells are expected to be completed by the end of April 2002. The sixth well has been plugged and abandoned.

In October 1998, the Falkland Islands consortium, in which Evergreen had a net 2% interest, finished drilling its second well. The two wells on Tranche A have established good source rock seal and potential reservoir rocks. In 2000, the consortium assigned the license interests and operatorship to AEL, in which Evergreen owns a 40% interest. AEL is currently evaluating data from all wells drilled to determine the future strategy for the acreage. AEL has extended the license fees through September 2002 and expects to renew the licenses in October 2002 for approximately $50,000.

At December 31, 2001 the Company held leases representing 1.2 million acres in Chile. The Company is awaiting government approval of a moratorium for the third and last year of an exploration period. If the next exploration period is entered, the Company will be required to drill a well in Chile within two years from the beginning of the next exploration period. The cost and depth of the well will be at the discretion of the Company but will require approval of the Chilean Minister of Mining.

(4) NOTE PAYABLE

The Company currently has a $200 million revolving credit facility with a bank group (the "Banks"). The credit facility is available through July 1, 2003. Advances pursuant to this credit facility are limited to a borrowing base, which is presently $200 million. The Company may elect to use either the London interbank offered rate, or LIBOR, plus a margin of 1.125% to 1.50% or the prime rate plus a margin of 0% or 0.25%, with margins on both rates determined on the average outstanding borrowings under the credit facility. The borrowing base is redetermined semi-annually by the Banks based upon reserve evaluations of Evergreen's oil and gas properties. An average annual commitment fee of 0.3125% is charged quarterly for any unused portion of the credit line. The agreement is collateralized by all domestic oil and gas properties and guaranteed by substantially all of the Company's subsidiaries. The credit agreement also contains certain net worth, leverage and ratio requirements. The Company was in compliance with all loan covenants at December 31, 2001 and 2000. At December 31, 2001 and 2000, Evergreen had $81,000,000 and $149,748,000, respectively, of outstanding borrowings under this credit facility, with an interest rate of 3.5% and 7.8%, respectively. The Company is currently in negotiations with the Banks to extend the credit facility to July 1, 2005.

(5) SENIOR CONVERTIBLE NOTES

In December 2001, the Company issued $100 million in senior unsecured convertible notes. The notes are due in 2021 and bear interest at a fixed annual rate of 4.75%, which is to be paid in cash on June 15 and December 15 of each year. In addition to the interest discussed above, the Company will pay contingent interest to the holders of the notes if the average trading price of the notes for an established number of days exceeds 120% or more of the principal amount of the notes. The rate of contingent interest payable in respect to any six-month period will equal the greater of (1) a per annum rate equal to 5% of the Company's estimated per annum borrowing rate for senior non-convertible

fixed-rate debt with a maturity date comparable to the notes or (2) 0.30% per annum. In no event may the contingent interest rate exceed 0.40% per annum.

The notes are general unsecured obligations, ranking on a parity in right of payment with all of Evergreen's existing and future senior indebtedness, and senior in right of payment with all of Evergreen's future subordinated indebtedness. The notes are due on December 15, 2021 but are redeemable at either the Company's option or the holder's option on other specified dates. The Company may redeem the notes at its option in whole or in part beginning on December 20, 2006, at 100% of their principal amount plus accrued and unpaid interest (including contingent interest). Holders of the notes may require the Company to repurchase the notes if a change in control of the Company occurs. Holders may also require the Company to repurchase all or part of the notes on December 20, 2006, December 15, 2011 and December 15, 2016 at a repurchase price of 100% of the principal amount of the notes plus accrued and unpaid interest (including contingent interest). On December 20, 2006, the Company may pay the repurchase price in cash, in shares of common stock, or in any combination of cash and common stock. On December 15, 2011 and December 15, 2016, the Company must pay the repurchase price in cash.

The notes are convertible into common stock of Evergreen under certain circumstances as discussed below at a conversion price of $50 per share, subject to certain adjustments. The notes can be converted at the option of the holder if for a specified period of time, the closing price of the Company's common stock exceeds 110% of the $50 conversion price or if the average trading value of the notes for a specified period of time is less than 105% of an average conversion value as defined by the indenture governing the notes. The notes may also be converted into common shares of the Company at the election of the holder upon notice of redemption, or at any time the notes are rated by either Moody's Investors Service, Inc. or Standard & Poor's Rating Group and the credit rating initially assigned to the notes by either such rating agency is reduced by two or more ratings levels, or upon the occurrence of certain corporate transactions including a change in control or the distribution to current holders of the Company's common stock certain purchase rights or any other asset that has a value exceeding 10% of the sale price of the common stock on the day preceding the declaration date of the distribution of such assets.

At December 31, 2001, the Company accrued approximately $185,000 in interest related to these notes, which is included in accrued expenses on the Company's consolidated balance sheet. No shares were included in the dilutive shares outstanding at December 31, 2001, as none of the events discussed above that would make the notes convertible into common shares of the Company's stock had occurred as of December 31, 2001.

(6) INCOME TAXES

The provision for deferred income taxes consisted of the following:

	Years Ended December 31,		
	2001	**2000**	**1999**
	(In Thousands)		
Federal	$ 20,625	$ 9,361	$ 2,830
State	2,213	1,334	438
	$ 22,838	$ 10,695	$ 3,268
Income tax for continuing operations	$ 22,838	$ 10,695	$ 2,979
Income tax for discontinued operations			289
Total income tax provision deferred	$ 22,838	$ 10,695	$ 3,268

	Years Ended December 31,		

The deferred income tax provision shown above excludes amounts related to the tax benefit of non-qualified stock options exercised in 2001 for which the benefit was credited directly to stockholders' equity.

A reconciliation of income tax computed at the federal and state statutory tax rates and the Company's effective tax rate is as follows:

	Years Ended December 31,		
	2001	**2000**	**1999**
Federal statutory rate	35.0%	34.0%	34.0%
State statutory rate, net of federal benefit	3.0%	3.3%	3.3%
Other	(0.8)%	1.3%	1.6%
Effective tax rate	37.2%	38.6%	38.9%

The components of the net deferred tax assets and liabilities are shown below:

	December 31,	
	2001	**2000**
	(In Thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 5,639	$ 8,393
Percentage depletion carryforwards	1,328	1,303
Tax credits, net of valuation allowance of $3,513 and $4,116	2,096	
Other	446	695
Total deferred tax assets, net	9,509	10,391
Deferred tax liabilities		
Depreciation, depletion and amortization	(43,811)	(27,609)
Other	(400)	
Total deferred tax liabilities	(44,211)	(27,609)
Net deferred tax liability	$ (34,702)	$ (17,218)

As of December 31, 2001, the Company had net operating loss carryforwards for tax purposes of approximately $14,800,000, which expire beginning in 2010 through 2018. Additionally, the Company had tax credit carryforwards for tax purposes of approximately $5,609,000, $5,421,000 which relate to state tax credits and will expire beginning in 2002 through 2013.

The state tax credits are subject to limitation and the Company has concluded that, based upon expected future results, the future reversals of taxable temporary differences and the tax benefits derived from the exercise of non-qualified employee stock options, there is no reasonable assurance that the entire tax benefit of the tax credits can be used. Accordingly, a valuation allowance has been established.

Included in deferred income taxes payable at December 31, 2001 are the tax effects of unrealized gains on the Company's available for sale investments of $389,000 and unrealized loss on the interest rate swap of $75,000.

(7) REDEEMABLE PREFERRED STOCK

In connection with the September 2000 property acquisition as discussed in Note 3, the Company issued 100,000 shares of mandatory redeemable preferred stock, with an aggregate liquidation value of $100 million, as part of the purchase consideration. Each share had a liquidation and redemption value of $1,000, plus accrued dividends. The Company redeemed the stock on December 22, 2000 using new borrowings under its credit facility. The preferred stock earned $2,929,000 of dividends from September 1, 2000 through December 22, 2000 at an annual rate of 9.5%.

(8) STOCKHOLDERS' EQUITY

Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended December 31,		
	2001	2000	1999
	(In Thousands, Except Per Share Data)		
Numerator:			
Net income from continuing operations	$ 38,527	$ 16,992	$ 4,675
Gain on disposal of discontinued operations, net			452
Preferred stock dividends		(2,929)	
Numerator for basic earnings per share income available to common stockholders	$ 38,527	$ 14,063	$ 5,127
Numerator for dilutive earnings per share income available to common stockholders after assumed conversions	$ 38,527	$ 14,063	$ 5,127
Denominator:			
Denominator for basic earnings per share weighted average shares	18,534	15,433	12,953
Effect of dilutive securities:			
Stock options and warrants	876	772	680
Stock to be issued (Note 3)		31	
Dilutive potential common shares	876	803	680
Denominator for diluted earnings per share adjusted weighted average shares and assumed conversions	19,410	16,236	13,633
Basic income per common share:			
From continuing operations	$ 2.08	$ 0.91	$ 0.36

	Years Ended December 31,		
From discontinued operations			0.03
Basic income per common share	$ 2.08	$ 0.91	$ 0.39
Diluted income per common share:			
From continuing operations	$ 1.98	$ 0.87	$ 0.34
From discontinued operations			0.03
Diluted income per common share	$ 1.98	$ 0.87	$ 0.37

For the years ended December 31, 2000 and 1999 all common stock equivalents were included in the computation of diluted earnings per share. As discussed in Note 5, the Company issued $100 million in senior convertible notes in December 2001 that are convertible into shares of common stock under certain circumstances. At December 31, 2001, no common stock equivalents were included in the computation of diluted earnings per share related to these convertible senior notes as no circumstances occurred that would cause them to be convertible.

Stock Issued for Services

During the years ended December 31, 2001, 2000 and 1999, the Company issued common stock valued at $876,000, $632,000 and $801,000 as bonuses to certain employees. During the years ended December 31, 2001 and 2000, the Company issued common stock to directors for directors' fees valued at $22,000 and $15,000. During 2000, the Company also issued common stock valued at $75,000 to a company for consulting services.

Stock Issued for Property Interests

Effective September 30, 1999, Evergreen acquired XYZ for $5 million. The purchase price consisted of $2.5 million in cash and 120,000 shares of Evergreen stock valued at $2.5 million. Also during the year ended December 31, 1999, miscellaneous property interests and surface rights were acquired in exchange for 55,996 shares of the Company's common stock valued at $921,000.

On January 20, 2000, the Company acquired additional interests in the Raton Basin in exchange for 309,834 shares of Evergreen common stock valued at approximately $5.6 million.

Effective September 1, 2000, Evergreen acquired property in the Raton Basin for $181.5 million. The purchase price consisted of $71.5 million in cash ($70.0 million in cash paid at closing and $1.5 million in post closing adjustments), $100.0 million in mandatory redeemable preferred stock and 201,748 shares of Evergreen stock valued at $6.0 million. On January 5, 2001, the Company issued an additional 116,009 shares of Evergreen stock valued at $4.0 million as additional purchase price consideration. See Note 3 for further discussion.

During the year ended December 31, 2001, the Company issued 39,690 shares of stock for property interests and right of ways valued at $1.2 million, which included 23,200 shares valued at $750,000 as partial consideration for a 100% working interest in 1,085,000 acres in Northern Ireland and the Republic of Ireland.

Other Equity Transactions

During the year ended December 31, 1999, the Company repurchased 100,000 shares of its common stock on the market at prices ranging from $16 to $19.19 per share for a total of $1.7 million. During the year ended December 31, 2001, the Company repurchased 10,000 shares of its common stock on the market at $35.35 per share for a total of $354,000.

Public Offerings of Common Stock

On June 22, 1999, the Company completed a public offering of its common shares, whereby it sold 3,162,500 shares at $22.00 per share. Proceeds, net of underwriters' commissions and expenses of $4.4 million, were $65.1 million, of which $58 million and $3.6 million were used to pay off the Company's line of credit and capital lease obligation, respectively.

On November 20, 2000, the Company completed a public offering of its common shares, whereby it sold 3,008,300 shares at $29.375 per share. Proceeds, net of underwriters' commissions and expenses of $4.9 million, of $83.5 million were used to reduce the balance on the Company's line of credit.

Shareholder Rights Plan

On July 7, 1997, the Board of Directors adopted a Shareholder Rights Plan ("Rights Plan"), pursuant to which stock purchase rights (the "Rights") were distributed as a dividend to the Company's common stockholders at a rate of one Right for each share of common stock held of record as of July 22, 1997 and for each share of stock issued thereafter. The Rights Plan is designed to enhance the Board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect shareholders against attempts to acquire the Company by means of unfair or abusive takeover tactics that have been prevalent in many unsolicited takeover attempts.

Under the Rights Plan, the Rights will become exercisable only if a person or a group (except for 20% shareholders existing at the time the Rights Plan was adopted) acquires or commences a tender offer for 20% or more of the Company's common stock. Until they become exercisable, the Rights attach to and trade with the Company's common stock. The Rights will expire July 22, 2007. The Rights may be redeemed by the continuing members of the Board at $.001 per Right prior to the day after a person or group has accumulated 20% or more of the Company's common stock.

(9) STOCK OPTIONS AND WARRANTS

On May 12, 1997, the Board of Directors adopted, and the Company's shareholders subsequently approved, an Initial Stock Option Plan (the "Plan"), whereby employees may be granted incentive options to purchase up to 500,000 shares of the common stock of the Company. The exercise price of incentive options must be equal to at least the fair market value of the common stock as of the date of grant. As of December 31, 2001, the Company had granted 500,000 options available under the Plan.

Under the terms of the Company's Key Employee Equity Plan, options and/or warrants were granted to key employees at not less than the market price of the Company's common stock on the date of grant. The purpose of the warrants are to reward directors and key personnel for past performance and to give them an incentive to remain with the Company and to induce directors to take all or part of their non-executive directors' compensation in the form of common stock.

On June 16, 2000, the Company's stockholders approved the 2000 Stock Incentive Plan (the "2000 Plan"). Under the 2000 Plan, the Company may grant options to purchase up to 1,000,000 shares of its common stock, plus an annual increase equal to the lesser of either 150,000 shares or an amount determined by the Board of Directors. The Board of Directors approved increases of 150,000 for 2001 and 2002. Awards which may be granted under the 2000 Plan include incentive stock options, non-qualified stock options, stock appreciation rights, restricted stock awards and restricted units. As of December 31, 2001, the Company had granted 934,000 awards under the 2000 Plan.

During the year ended December 31, 2001, the Company granted options to purchase 462,300 shares to its directors, officers and employees at exercise prices of $29.50 to $36.00. During the year ended December 31, 2000, the Company granted options to purchase 679,280 shares to its directors, officers and employees at exercise prices ranging from $18.50 to $27.44. During the year ended

December 31, 1999, the Company granted options to purchase 221,301 shares to its directors and officers at an exercise price of $14.625.

	Years Ended December 31,		
	2001	**2000**	**1999**

	Years Ended December 31,					
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, beginning of period	1,728,936	$ 15.16	1,106,281	$ 9.57	1,083,218	$ 8.17
Granted	462,300	33.20	679,280	23.84	221,301	14.625
Exercised	(503,372)	8.49	(43,625)	8.02	(188,238)	7.24
Forfeitures	(16,750)	24.36				
Expired			(13,000)	16.81	(10,000)	12.58
Outstanding, end of period	1,671,114	$ 22.10	1,728,936	$ 15.16	1,106,281	$ 9.57
Options and warrants exercisable, end of period	619,426	$ 14.52	820,187	$ 8.50	762,781	$ 7.94
Weighted average per share fair value of options and warrants granted during the period		$ 22.40		$ 18.66		$ 9.48

SFAS No. 123, "Accounting for Stock-Based Compensation," requires the Company to provide pro forma information regarding net income and net income per share as if compensation costs for the Company's stock option plans and other stock awards had been determined in accordance with the fair value based method prescribed in SFAS No. 123. The Company estimated the fair value of each stock award at the grant date by using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants in the year ended December 31, 1999: dividend yield at 0%; expected volatility of approximately 43%; risk-free interest rate of 4.5% and expected lives of five and ten years for the warrants and options. Assumptions used for the year ended December 31, 2000: dividend yield at 0%; expected volatility of approximately 43% to 50%; risk-free interest rates of 4.82% to 5.74% and expected lives of five to ten years for the warrants and options. Assumptions for the year ended December 31, 2001: dividend yield at 0%; expected volatility of approximately 51%; risk-free interest rate of 4.29% to 5.10% and expected lives of five to ten years for the warrants and options.

Under the accounting provisions of SFAS No. 123, the Company's net income and net income per share would have been adjusted to the following pro forma amounts:

	Years Ended December 31, 2000					
	2001		2000		1999	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
	(In Thousands, Except Per Share Data)					
Basic net income available to common stockholders (Note 8):						
Income from continuing operations	$ 38,527	$ 35,790	$ 14,063	$ 12,702	$ 4,675	$ 4,131
Discontinued operations					452	452
Net income	$ 38,527	$ 35,790	$ 14,063	$ 12,702	$ 5,127	$ 4,583
Basic income per common share:						
From continuing operations	$ 2.08	$ 1.93	$ 0.91	$ 0.82	$ 0.36	$ 0.32

	Years Ended December 31, 2000					
From discontinued operations					0.03	0.03
Basic income per common share	$ 2.08	$ 1.93	$ 0.91	$ 0.82	$ 0.39	$ 0.35
Diluted net income (Note 8):						
Income from continuing operations	$ 38,527	$ 35,790	$ 14,063	$ 12,702	$ 4,675	$ 4,131
Discontinued operations					452	452
Net income	$ 38,527	$ 35,790	$ 14,063	$ 12,702	$ 5,127	$ 4,583
Diluted income per common share:						
From continuing operations	$ 1.98	$ 1.84	$ 0.87	$ 0.78	$ 0.34	$ 0.31
From discontinued operations					0.03	0.03
Diluted income per common share	$ 1.98	$ 1.84	$ 0.87	$ 0.78	$ 0.37	$ 0.34

The following table summarizes information about stock options and warrants outstanding at December 31, 2001:

	Outstanding			Exercisable	
Range of Exercise Prices	**Number Outstanding at 12/31/01**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable at 12/31/01**	**Weighted Average Exercise Price**
$ 7.00	236,560	1.85	$ 7.00	236,560	$ 7.00
13.00	122,549	6.00	13.00	80,861	13.00
14.63	219,500	6.78	14.63	114,500	14.63
18.50	240,555	7.96	18.50	61,055	18.50
27.38	251,200	8.81	27.38	89,200	27.38
27.44	138,450	8.83	27.44	34,950	27.44
29.50 - 36.00	462,300	9.79	33.19	2,300	36.00
$ 7.00 - 36.00	1,671,114	7.50	$ 22.10	619,426	$ 14.52

(10) MAJOR CUSTOMERS

During the years ended December 31, 2001, 2000 and 1999, the Company made sales to certain unrelated entities which individually comprised greater than 10% of total natural gas revenues. The following is a table summarizing the percentage provided by each customer.

	Years Ended December 31,		
Customer	**2001**	**2000**	**1999**
A	46%	61%	49%
B	31%	22%	%
C	10%	12%	24%
D	%	%	18%

At December 31, 2001, four customers represented 32%, 31%, 18% and 10% of natural gas sales accounts receivable.

(11) SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Cash paid during the years ended December 31, 2001, 2000 and 1999 for interest was approximately $9,247,000, $3,599,000, and $2,194,000, respectively. During the years ended December 31, 2001, 2000 and 1999, approximately $1,172,000, $626,000 and $351,000 of interest paid was capitalized, respectively.

See Notes 3, 7, 8, and 9 for additional non-cash transactions during the years ended December 31, 2001, 2000 and 1999.

(12) COMMITMENTS AND CONTINGENCIES

Evergreen's current firm transportation commitments with Colorado Interstate Gas Co. ("CIG") are 97 MMcf of gross gas sales per day. The Company has committed to an additional 30 MMcf per day, subject to a ramp-up schedule which anticipates 5 MMcf per day increments each four months from June 2002 through February 2004. Thus, Evergreen's total transportation obligations committed to will increase in increments to 127 MMcf per day by February 2004. If the Company is unable to fulfill its transportation commitments, amounts paid for transportation on up to 41 MMcf per day can be credited toward future transportation costs through August 2006.

Under terms of the transportation agreements, the Company has committed to pay the following transportation reservation charges with CIG to provide firm transportation capacity rights:

Year Ending December 31,	Reservation Charges
	(In Thousands)
2002	$ 10,779
2003	12,353
2004	13,438
2005	12,904
2006	12,904
Thereafter	71,982
	$ 134,360

In May 1998, the Company entered into a new ten-year office lease, which was amended in March 2001 to include additional space, that now provides for lease payments of approximately $620,000 per year. Rental expense was approximately $559,000, $290,000, and $268,000 for the years ended December 31, 2001, 2000 and 1999, respectively. The Company also leases equipment under non-cancelable operating leases with maturity dates through the year ending 2004.

The following table summarizes the future minimum lease payments under all noncancelable operating lease obligations.

Year Ending December 31,	Future Minimum Lease Payments
	(In Thousands)
2002	$ 2,288
2003	1,159
2004	825
2005	637
2006	663
2007 and Thereafter	889
	$ 6,461

Effective January 1, 1997, the Company implemented a 401(k) plan for all eligible employees. The Company provides a matching contribution up to a certain percentage of the employees' contributions. The 401(k) plan also provides for a profit sharing contribution determined at the discretion of the Company. The total matching and profit sharing contributions for the years ended December 31, 2001, 2000 and 1999 were approximately $247,000, $179,000 and $46,000, respectively.

At December 31, 2001, the Company had entered into agreements with various vendors to construct well service equipment and gas collection assets at a total cost of approximately $13 million. As of December 31, 2001, approximately $2.5 million was paid as deposits on such equipment, which is included in property and equipment on the Company's consolidated balance sheet. Subsequent to December 31, 2001, the Company committed to purchase two additional compressors at a combined estimated cost of approximately $3.5 million.

The Company currently has a commitment to drill six wells in the Pioneer Unit in Alaska in 2002. Total expected costs related to this commitment are estimated to be approximately $3 million. The Company has also entered into a joint venture agreement with a work commitment covering 29,000 acres of coal bed methane properties in Huerfano County, Colorado, in the northern end of the Raton Basin. Under the agreement, Evergreen will spend $2 million through September 30, 2002 to earn a 50% working interest in the properties, which currently contain 15 shut-in wells. The properties are located approximately 20 miles north of Evergreen's existing 274,000 acres of coal bed methane properties in Las Animas County, Colorado. Evergreen's planned expenditures will be primarily for drilling, completions, workovers, equipment and fracture stimulations. As of December 31, 2001, the Company had incurred approximately $300,000 toward the work commitment of $2 million.

As of December 31, 2001, the Company had entered into the following fixed-price physical delivery contracts to sell its gas production (the Company's hedging contracts are denoted in MMBtu's, which convert on an approximate 1-for-1 basis into Mcf):

a maximum of 4 MMcf per day from January 1, 2001 through April 30, 2003, at a price of $2.40 per Mcf plus transportation costs, and

10 MMcf per day from January 1, 2001 through March 31, 2003 for the lesser of then current market price or a gross price of $2.45 per Mcf.

In consideration for the extension of the $2.45 contract, Evergreen received $1,762,000 over the 12-month period ended October 31, 2000, which is being amortized over the contract term. As of December 31, 2001, $565,000 was recognized as deferred revenue and will be recognized as revenue in future periods.

Subsequent to December 31, 2001 through February 15, 2002, the Company entered into two commodity swap agreements. One contract is for 20 MMcf per day from March 1, 2002 through June 30, 2002 at a hedge price of $2.315 per Mcf and the other contract is for 20 MMcf per day from March 1, 2002 through June 30, 2002 at a hedge price of $2.325 per Mcf. The contracts provide for the Company to receive or make payments based upon the differential between the hedge price and the market gas price, as defined in the contracts, for the notional quantity.

(13) RELATED PARTIES AND OTHER

On February 9, 2001, Evergreen closed a transaction with KFx Inc. ("KFx") under which KFx sold to Evergreen a portion of its convertible preferred stock investment in its Pegasus Technologies, Inc. subsidiary ("Pegasus"), representing an approximate 8.8% as converted interest in Pegasus, for $1.5 million. Under the terms of the agreement, the repurchase date was January 31, 2002 unless Evergreen elected to extend it to January 1, 2003. Evergreen has extended the repurchase date to January 1, 2003 in consideration for the option to purchase additional convertible preferred stock in Pegasus for $1.2 million any time prior to January 1, 2003, which is redeemable on or before January 1, 2003 for $1.6 million. In certain circumstances, Evergreen can elect to exchange this interest in Pegasus, valued at $2 million, and any subsequently acquired interest in Pegasus, for common stock of KFx at $3.65 per share, subject to certain adjustments. In addition, Evergreen was provided with a five-year warrant to purchase 1 million shares of KFx common stock at $3.65 per share, subject to certain adjustments, which includes the reduction in the warrant exercise price to $2.25 per share upon KFx's retirement of certain outstanding debentures. No value has been assigned to the warrants or the purchase option as the Company does not believe the value to be significant given current stock liquidity factors. Should the Company elect to exercise the option to acquire more preferred stock at a discount, a gain could be recorded in the future which could affect the Company's carrying value and resulting gain. The President and Chief Executive Officer of Evergreen is on the board of directors of KFx. The Chief Financial Officer of Evergreen is on the board of directors of Pegasus.

A director of the Company is a partner in a law firm that acts as counsel to the Company on various matters. The Company paid legal fees and expenses to the law firm of approximately $157,000, $139,000 and $207,000 in 2001, 2000 and 1999, respectively.

(14) DISCONTINUED OPERATIONS

Effective February 18, 1999, Evergreen sold its 49% interest in Maverick to the managing members of Maverick for approximately $2,258,000. The sale resulted in a gain, net of tax, of approximately $452,000 or $0.03 per diluted share. The Company was also released from its guarantee of certain debt obligations of Maverick. This transaction was accounted for as a discontinued operation and the results of operations were excluded from continuing operations in the consolidated statements of income for all periods presented.

(15) SUPPLEMENTAL OIL AND GAS INFORMATION (Unaudited)

Costs incurred in Oil and Gas Exploration and Development Activities

The Company's oil and gas activities are conducted in the United States, the United Kingdom, Northern Ireland and the Republic of Ireland, the Falkland Islands and Chile. See Note 3 for additional information regarding the Company's oil and gas properties. The following costs were

incurred in oil and gas acquisition, exploration, development, gas gathering and producing activities during the following periods:

	United States	United Kingdom	N. Ireland/ Republic of Ireland	Falkland Islands	Chile	Total
			(In Thousands)			
Year Ended December 31, 2001						
Acquisition costs:						
Proved	$ 16,202	$	$	$	$	$ 16,202
Unproved	1,891					1,891
Gas collection	2,153					2,153
Development	51,512					51,512
Gas collection	35,310					35,310
Exploration	3,587	3,574	7,334			