RANGE RESOURCES CORP
Form 10-K/A
April 08, 2004

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A

Amendment No. 1

(Mark one)

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

For the fiscal year ended December 31, 2003

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 0-9592

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**34-1312571** (IRS Employer Identification No.)
777 Main Street, Suite 800, Fort Worth, Texas (Address of Principal Executive Offices)	**76102** (Zip Code)

Registrant s Telephone Number, Including Area Code
(817) 870-2601

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

Title Of Each Class	Name Of Each Exchange On Which Registered
Common Stock, $.01 par value	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 þ 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. o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

Yes þ No o

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 30, 2003 was $342,117,000.

As of February 26, 2004, there were 56,674,425 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant s Proxy Statement to be furnished to stockholders in connection with its 2004 Annual Meeting of Stockholders are incorporated by reference in Part III of this Report.

TABLE OF CONTENTS

Table of Contents

EXPLANATORY NOTE

Range Resources Corporation (the Company) is filing this Amendment No. 1 to our Annual Report on Form 10-K/A for the year ended December 31, 2003 as filed by the Company on March 3, 2004 to revise an inadvertent inaccuracy in footnote 19 to the consolidated financial statements concerning unaudited standardized measure and changes in standardized measure. The Company is not making any other changes to the 10-K. For convenience and ease of reference, the Company is filing this Annual Report in its entirety with the applicable changes. Unless otherwise stated, all information contained in the amendment is as of March 3, 2004, the filing date of the Annual Report of Form 10-K for the year ended December 31, 2003. This Amendment No. 1 to the Annual Report on Form 10-K/A should be read in conjunction with our subsequent filings with the SEC.

(i)

Table of Contents

RANGE RESOURCES CORPORATION

Annual Report on Form 10-K
Year Ended December 31, 2003

PART I

ITEM 1. BUSINESS

General

Range Resources Corporation (the Company or Range) is engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company seeks to increase its reserves and production through internally generated drilling projects coupled with complementary acquisitions. The Company holds its Appalachian assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. (Great Lakes). The Company s interest in Great Lakes assets and operations is consolidated in its financial statements. At December 31, 2003, the Company had 685 Bcfe of proved reserves, having an estimated pretax present value of $1.4 billion based on constant NYMEX prices of $32.52 per barrel and $6.19 per Mmbtu. The Company s proved reserves are 71% natural gas by volume, 72% developed and 93% operated. At year-end, the Company had a reserve life index of 11 years and owned 834,000 (376,000 net) acres of undeveloped leasehold.

History

The Company was incorporated in 1980 under the name Lomak Petroleum, Inc. by a group of investors who had been developing oil and gas properties since 1976 in the Appalachian Basin. Shortly after its incorporation in 1980, the Company completed an initial public offering and began trading on the NASDAQ. Throughout the 1980 s, the Company conducted drilling operations, primarily in the Appalachian Basin and to a lesser extent in Michigan and Texas. After several years of depressed oil and gas prices, in 1988 the Company began to focus on acquiring producing oil and gas properties. From 1988 through 1996, total assets grew from less than $10 million to nearly $300 million through a series of smaller acquisitions which expanded the Company s operations into the Southwest and Gulf Coast regions. In 1996, the Company s common stock was listed on the New York Stock Exchange. In 1997 and 1998, two large acquisitions were completed which increased total assets to over $900 million. Upon completing the second acquisition, the Company changed its name to Range Resources Corporation. The two large acquisitions were financed primarily with debt. At year-end 1998, due to its high debt and coupled with the poor performance of the two large acquisitions and falling oil and gas prices, the Company was overleveraged. In 1999, the Company initiated a series of activities to reduce debt and strengthen its financial position. These activities included reducing capital expenditures, selling non-core assets, creating the Great Lakes joint venture and exchanging common stock for outstanding debt and convertible securities. As a result, since year-end 1998, debt and convertible securities have been reduced by approximately $400 million or roughly 50%.

In addition to rebuilding its financial strength, the Company instituted efforts to implement a more balanced strategy of internally generated drillbit growth coupled with complementary acquisitions. These efforts included significantly expanding its technical staff, upgrading its management team and increasing its acreage and seismic expenditures. Currently, the Company believes it has developed a substantial inventory of drilling projects balanced between lower risk and moderate risk development and higher risk exploration. The Company s more balanced approach has resulted in much improved operating and financial results in 2002 and 2003. During this two year period, the Company increased its proved reserves 33% at an average finding and development cost of $1.11 per mcfe. The Company has announced a $126.0 million 2004 capital budget excluding acquisitions. The budget includes $109.0 million to drill 409 gross (237 net) wells and initiate 35 gross (29 net) recompletions. Also included is $15.0 million for land and seismic and $2.0 million for the expansion and enhancement of gathering systems pipelines and facilities.

Description of the Business

Strategy. From 1988 through 1999, the Company s strategy centered on the acquisition of producing oil and gas properties and the subsequent development of the acquired properties. During that period, total assets grew from less than $10 million to over $900 million. In 1999, the Company initiated a series of activities to strengthen its financial position while simultaneously re-evaluating its growth strategy. In response to its larger size and due to the increased competition for acquisitions, the Company decided to implement a more balanced strategy of internally generated drillbit growth coupled with complementary acquisitions. The Company expanded its technical staff, upgraded its management team and significantly increased capital expenditures for acreage and seismic. As a result, the Company s drilling inventory has evolved from an inventory of primarily lower risk, lower return projects to a larger, more balanced portfolio of lower risk development, moderate risk exploitation and higher risk exploration projects. With its larger, more balanced drilling inventory, the objective each year is to generate baseline production and reserve growth through the drilling projects that are diversified according to risk and geographically divided among its three divisions. Acquisitions of producing properties are intended to complement the Company s drilling activities and provide incremental growth in production and reserves.

The Company s more balanced growth strategy is intended to provide better returns on capital expended and more consistent operating and financial results over a multi-year period. As part of its effort to generate consistent operating and financial results, the Company seeks to maintain a reserve life of no less than 10 years. By maintaining a 10+ year reserve life, the Company believes it is reducing the reinvestment risk associated with a shorter reserve life. Also, to help insure that drilling related capital expenditures can be funded through internally generated cash flow, the Company enters into hedging arrangements to reduce the volatility of oil and gas prices, therefore increasing the predictability of its cash flow. During the period it was reducing debt and enhancing its financial position, the Company primarily used a series of swap arrangements to lock in oil and gas prices. Beginning in 2003, the Company began to use zero-premium collars to provide downside protection from falling prices while retaining a portion of the upside potential of rising prices. In the future, the Company anticipates it will use a combination of swaps and collars to reduce the volatility of oil and gas prices, increasing the predictability of its cash flow and locking in returns generated on capital expended.

At year-end 2003, the Company had 2,135 proven recompletion and development projects in inventory. Given current oil and gas prices, hedges and its development inventory, the Company believes it can achieve growth in reserves, production, cash flow and earnings over the next several years. The Company s 834,000 gross (376,000 net) acres of undeveloped leasehold and 1,255,000 gross acres (652,000 net) developed leasehold provide significant long-term exploration and development potential.

Development. Development projects include recompletions of existing wells, infill drilling and the installation of secondary recovery projects. Such projects are pursued within core areas where the Company has competitive operational and technical experience. At December 31, 2003, the Company had an inventory of 1,883 proven drilling locations and 252 proven recompletions. During 2004, the Company plans to drill 247 proven locations and recomplete 48 wells. In addition, the Company plans to drill more than 145 unproved projects. The following table summarizes 2003 development activity and changes in the inventory of proved development projects:

	Development Projects		
	Drilling Locations	**Recompletion Opportunities**	**Total**
Beginning of 2003	1,770	277	2,047
Drilled	(173)	(26)	(199)
Added	376	25	401
Deleted & other	(90)	(24)	(114)
End of 2003	1,883	252	2,135

Exploration. Onshore exploration acreage totals 448,000 gross (182,000 net) acres. The projects target deeper horizons in existing fields as well as trend areas. Offshore exploration focuses on the shallow waters of the Gulf of Mexico where the Company owns a license on 3-D seismic data covering 4.0 million contiguous acres. The Company has offshore leases covering 149,000 (42,000 net) acres on which 8 specific projects have been identified to date. The Company s strategy limits risk by judicious use of state-of-the-art exploration technology, extensive geologic and engineering project analysis and a thorough review of capital expenditures by management. At times, on certain exploratory wells, other companies pay a disproportionate share of exploration costs to earn an interest. The Company currently expects to participate in as many as 28 exploratory wells in 2004.

Acquisitions. After two years during which the Company withdrew from the market, an acquisition program was reinstated in 2002. In 2002, several small acquisitions were completed. In December 2003, the Company completed the purchase of 603 wells on 38,000 gross (32,000 net) acres of leases together with associated reserves and production equipment which are adjacent to the Company s Conger Field properties in Sterling County, Texas. The purchase price should approximate $87.1 million after normal post-closing adjustments and including $2.1 million of estimated asset retirement obligations. The Company will continue to pursue acquisitions in 2004 with a focus on purchases of properties in existing core areas.

Development and Exploration

In 2003, the Company spent $206.9 million on oil and gas related capital expenditures, an increase of 86%, with $156.4 million expended in the Southwest, $30.4 million in Appalachia and $20.1 million in the Gulf Coast. The spending funded the drilling of 358 (200.3 net) new wells, 56 (45.3 net) recompletions, $11.5 million of acreage and seismic and $95.3 million of producing property acquisitions (See Note 16 to the Consolidated Financial Statements). Exploration and development spending brought 23.2 Bcfe of proved non-producing reserves on stream and added a net 68.3 Bcfe of new reserves. Producing property acquisitions added 90.3 Bcfe of new reserves. Reserves added during the year replaced 286% of production (270% excluding pricing revisions).

Development

Development projects include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. Drilling prospects are geographically diverse and target a mix of potential oil and gas formations at varying depths. Development activities also include increasing reserves and production through aggressive cost control, upgrading lifting equipment, improving gathering systems and surface facilities and performing restimulations and refracturing operations. The following table sets forth the development inventory at December 31, 2003 by division:

	Development Projects		
	Drilling Locations	Recompletion Opportunities	Total
Southwest	169	166	335
Gulf Coast	13	34	47
Appalachia	1,701	52	1,753
Total	1,883	252	2,135

Exploration

Onshore. The Company currently has 40 onshore exploration projects on its 448,000 (182,000 net) acres. Most of the projects cover multiple drilling prospects, some with a number of targeted formations.

Gulf of Mexico. The Company owns a license on a 3-D seismic database covering 800 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana. In 2001, a joint venture was formed with two other companies to reprocess the data to identify and pursue exploration and development opportunities within a 4.0 million acre area. Range holds a 25% interest in the joint venture. The joint venture was awarded two blocks in the March 2001 lease sale. The joint venture plans to participate in at least two additional wells in 2004. The Company has also drilled one successful well using these data and plans to drill one additional well in 2004. The Company s current offshore leasehold inventory includes 37,000 gross (11,000 net) acres. To more fully exploit the seismic data base, it will be necessary to lease or farm-in additional acreage. To date, the joint venture has identified 39 specific prospects and leads on acreage not currently controlled. These projects generally target Miocene and Pliocene formations at depths ranging from 3,000 to 16,000 feet.

Oil and Gas Sales

Production revenue is generated through the sale of natural gas, crude oil and natural gas liquids (NGLs) from properties owned directly or through partnerships and joint ventures. The Company receives additional revenue from royalties. Production is sold to a number of purchasers, of which three account for more than 10% of oil and gas revenues. These three purchasers accounted for 49% of oil and gas revenues in 2003. The Company believes that the loss of any individual customer would not have a long-term material adverse effect. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices that production can be marketed. Factors outside the Company s control, such as international political developments, overall energy supply and demand, weather conditions, economic growth rates and other factors in the United States and elsewhere have had, and will continue to have, a significant effect on energy prices.

On an mcfe equivalent volume basis, 75% of the Company s 2003 production was natural gas. Gas is sold to utilities, marketing companies and industrial users. Gas sales are made pursuant to various contractual arrangements including month-to-month, one to three-year contracts at fixed or variable prices and, to a small extent, fixed prices for the life of the well. Contracts, other than those with fixed prices, contain provisions for price adjustment, termination and other terms customary in the industry. Oil is sold under contracts that can be terminated on 30 days notice. The price received is generally equal to a posted price set by major purchasers in the area. Oil and gas purchasers are selected on the basis of price, credit quality, and service. In 2003, gas revenues totaled $171.3 million or 76% of oil and gas revenues while revenues from oil and natural gas liquids totaled $55.1 million. Oil and gas revenues in 2003 increased 19% from the prior year due to higher production and higher prices.

Transportation, Gathering and Marketing

Transportation, gathering and marketing revenues are comprised of fees for the gathering and transportation of gas as well as oil and gas marketing income. Transportation, gathering and marketing revenues were $3.5 million in 2003, roughly level with the prior year. Gas transportation and gathering assets include (i) 50% ownership in approximately 5,000 miles of gas pipelines in Appalachia held through Great Lakes and (ii) a number of smaller gathering systems associated with producing properties outside of Appalachia. The Appalachian gathering systems transport a majority of Great Lakes gas production as well as third party gas to major trunk lines and directly to end-users. Third parties who transport gas through the gathering systems are charged a fee based on throughput.

The Company markets its own gas production and attempts to reduce the impact of price fluctuations through hedging. Approximately 1% of gas production is currently sold pursuant to fixed price end-user contracts at prices ranging from $1.25 to $7.28 per mcf (averaging $3.88 per mcf). The remaining 99% of gas production is sold at market (generally local index) related prices.

Hedging

The Company enters into hedging agreements to reduce the impact of volatile oil and gas prices. These contracts are entered into solely to hedge prices. Historically, the Company used swap agreements to hedge its production. In 2003, the Company began to use a combination of swap and collar arrangements. At December 31, 2003, hedges were in place covering 52.6 Bcf of gas at prices averaging $4.13 per mcf, 1.4 million barrels of oil at prices averaging $25.74 per barrel and 0.7 million barrels of NGLs at prices averaging $21.02 per barrel. The Company also has collars covering 6.6 Bcf of gas at weighted average floor and cap prices $4.14 to $6.19 and 1.2 million barrels of oil at weighted average floor and cap prices of $24.16 to $29.24. The fair value of the hedges, represented by the estimated amount that could be realized on immediate termination, approximated a pretax loss of $70.6 million at December 31, 2003. This loss is presented on the Company s Consolidated Balance Sheet as a net short-term unrealized loss of $53.7 million and a long-term unrealized loss of $16.9 million. Realized hedging gains and losses are determined monthly as hedges are financially settled and are included as increases or decreases in oil and gas revenues in the period the hedged production is sold. The realized loss relating to hedging in 2001 was $6.2 million. A hedging gain of $17.8 million was realized in 2002. A hedging loss of $60.4 million was realized in 2003. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly. Unrealized gains or losses on hedging contracts are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on the Company s Consolidated Balance Sheet as other comprehensive income (loss) (OCI), a component of stockholders equity. Through Great Lakes, the Company also has interest rate swap agreements (see Notes 6 and 7 to the Consolidated Financial Statements).

Independent Producer Finance (IPF)

IPF is a wholly owned subsidiary that provides capital to small oil and gas producers in exchange for dollar-denominated term overriding royalty interests. At year-end 2003, IPF s portfolio included 19 transactions having an aggregate book value of $12.6 million (net of $9.6 million of valuation allowances). The book value of the portfolio declined 48% in 2003 primarily due to $12.1 million of repayments received during the year. Since 2001, IPF has not entered into any new investment agreements and therefore, the portfolio should continue to decline from repayments, although IPF continues to fund requirements on existing transactions. The oil and gas reserves underlying

IPF s royalties are not included in the Company s reported proved reserves.

IPF provides valuation allowances against receivables that may not be recoverable. Increases and decreases in valuation allowances are reported as expenses. The IPF valuation allowance was increased $1.7 million, $4.2 million and $2.0 million in 2003, 2002 and 2001, respectively. IPF expenses also include general and administrative costs and interest expense. As dollar-denominated royalties, the transactions leave a portion of the commodity price risk with the producer. However, when price declines occur, IPF is exposed to losses. In addition, IPF is fully exposed to the individual operator s ability to successfully produce and develop the underlying reserves.

Table of Contents

Other Revenues

Other revenues is composed of ineffective hedging gains or losses, gains or losses on sale of assets and interest earned on cash balances and certain receivables. During 2003, other revenue amounted to a loss of $1.3 million including $1.2 million of ineffective hedging losses. During 2002, other revenue totaled a loss of $2.9 million which included $2.7 million of ineffective hedging losses, a $1.2 million write-down of marketable securities and a $715,000 favorable arbitration settlement. During 2001, other revenue totaled $490,000 and included $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to hedges utilizing Enron as the counterparty.

Competition

The Company encounters substantial competition in acquiring oil and gas leases, marketing production, securing personnel and conducting drilling and field operations. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independents, individual proprietors and others. Many competitors have financial and other resources substantially exceeding those of the Company. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. The ability of the Company to replace and expand its reserve base depends on its ability to attract and retain quality personnel, identify and acquire suitable producing properties and prospects for future drilling.

Historically, acquisitions have generally been financed through bank borrowings, the issuance of debt and equity securities and internally generated cash flow. Debt and equity markets are cyclical as is the price of oil and gas. The ability of the Company to obtain financing on satisfactory terms is sometimes uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise satisfactorily priced external capital in the future could have a material adverse effect on its business.

Governmental Regulation

The Company s operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been subject to, price controls, taxes and numerous other laws and regulations. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although the Company believes it is in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, the Company is unable to predict the future cost or impact of complying.

Securities Exchanges

Since 1998, 15.4 million shares of common stock have been issued in exchange for debt and convertible securities. The shares were exchanged for $96.7 million face value of 8.75% senior subordinated notes (the 8.75% Notes), 6% convertible subordinated debentures (the 6% Debentures), 5.75% trust preferred securities (the Trust Preferred Securities) and $2.03 convertible preferred stock (the $2.03 Preferred Stock). In September 2003, the Company exchanged $10.2 million in cash and $50.0 million of the newly issued Convertible Preferred for $79.5 million of the Trust Preferred Securities. The extent of any future dilution from exchanges will depend on a number of factors, including the number of shares issued, the price at which stock is issued or any newly issued securities are convertible into common stock and the price at which debt and convertible securities are reacquired.

Environmental Matters

The Company s operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency (EPA) issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect the Company s operations and financial position, as well as the industry in general. Management believes the Company is in substantial compliance with current applicable environmental laws and regulations. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. The Company did not have any material capital expenditures in connection with environmental remediation matters in 2003, nor does it anticipate that such expenditures will be material in 2004.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA and that such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and gas wastes are pending in certain states and these initiatives could have a significant impact on the Company. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment under environmental statutes, common law or both.

The Federal Water Pollution Control Act (FWPCA) imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into waters of the United States. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal National Pollutant Discharge Elimination System general permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The cost to comply with zero discharges mandated under federal and state law has not had a material adverse impact on the Company s financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

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

The U.S. Oil Pollution Act (OPA) requires owners and operators of facilities that could be the source of an oil spill into waters of the United States (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time to time that would alter the RCRA exemption by reclassifying certain oil and gas exploration and production wastes as hazardous wastes and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on the Company s operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on the capital expenditures, earnings or competitive position of the Company. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

Table of Contents

Risk Factors and Cautionary Statement for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

Certain information included in this report, other materials filed or to be filed by the Company with the Securities and Exchange Commission (SEC), as well as information included in oral statements or other written statements made or to be made by the Company contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words budget, budgeted, assumes, should, goal, anticipates, expects, believes, seeks, plans, estimates, intends, projects expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, and the Company undertakes no obligation to publicly update or revise any forward-looking statements.

With the previous paragraph in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by the Company or on its behalf.

Oil and natural gas prices are volatile, and an extended decline in prices would hurt our profitability and financial condition

The oil and natural gas industry is cyclical, and prices for oil and natural gas are volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. For example, in 1998 and early 1999, oil and natural gas prices fell, which contributed to losses we reported in those years. By early 2001, oil and natural gas prices reached levels above their historical norm. Prices declined in the second half of 2001 but have risen since mid-2002. Long-term supply and demand for oil and natural gas is uncertain and subject to a myriad of factors including technology, geopolitics, weather patterns and economics.

Many factors affect oil and natural gas prices including general economic conditions, consumer preferences, discretionary spending levels, interest rates and the availability of capital to the industry. Decreases in oil and natural gas prices from current levels could adversely affect our revenues, net income, cash flow and proved reserves. Significant and prolonged price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we will likely be unable to replace production.

Common shareholders will be diluted if additional shares are issued

Since 1998, the Company has exchanged 15.4 million shares of common stock for $96.7 million of debt and convertible securities, including the Trust Preferred Securities, 6% Debentures, 8.75% Notes and $2.03 Preferred Stock. The exchanges were made based on the relative market value of the common stock and the debt and convertible securities at the time of the exchange. During 2001, $17.4 million of debt and convertible securities was exchanged for common stock. During 2002, $10.4 million of debt and convertible were exchanged for common stock. During 2003, $880,000 of debt was exchanged for common stock. See Notes 6 and 18 to the Consolidated Financial Statements. While the exchanges have reduced interest expense, dividends and future repayment obligations, the larger number of common shares outstanding have a dilutive effect on existing shareholders. The Company s ability to repurchase securities for cash is limited by the $225.0 million secured revolving bank credit facility (the Senior Credit Facility) and the 7.375% senior subordinated notes (the 7.375% Notes) agreement. The Company continues to review alternatives to further strengthen its balance sheet by reducing debt and retiring securities. The Company may issue additional shares to fund capital expenditures, including acquisitions.

Table of Contents

Dividend restrictions

Restrictions on the payment of dividends and other restricted payments, as defined, are imposed under the Company s bank credit facility and the 7.375% Notes. Under the Senior Credit Facility, common and preferred dividends are permitted, subject to limitations. The terms of the 7.375% Notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings since the issuance of the notes. The Senior Credit Facility provides for a restricted payment basket of $20.0 million plus 50% of net income (excluding Great Lakes) plus 66-2/3% of distributions, dividends or payments of debt from or proceeds from sales of equity interests of Great Lakes plus 66-2/3% of net cash proceeds from common stock issuances. As of December 31, 2003, the Company had $37.5 million available under the Senior Credit Facility restricted payment basket and $18.6 million available under the 7.375% Notes restricted payment basket.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price volatility, we enter into hedging arrangements from time-to-time with respect to a portion of our future production. The goal of these hedges is to limit volatility and increase the predictability of cash flow. These transactions may limit our potential gains if oil and natural gas prices were to rise over the price established by the hedge. At December 31, 2003, we were party to hedging arrangements covering 52.6 Bcf, 1.4 million barrels of oil and 0.7 million barrels of NGLs. The hedges fair value was a pretax unrealized loss of $70.6 million. If oil and natural gas prices continue to rise, we could be subject to margin calls. In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected, the counterparties to our contracts fail to perform under the contracts or a sudden, unexpected event materially impacts oil or natural gas prices.

Information concerning our reserves and future net reserve 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 our control. Estimates of proved undeveloped reserves, which comprise a significant portion of our reserves, are by their nature uncertain. The reserve data included or incorporated by reference is estimated. Although we believe these estimates are reasonable, actual production, revenues and reserve expenditures will likely vary from estimates, and these variances could be material.

The accuracy of any reserves estimate is a function of the quality of available data, engineering and geological interpretation and judgment, assumptions used regarding quantities of oil and natural gas in place, recovery rates and future prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and such variances may be material. Any variance in the assumptions could materially affect the estimated value of the reserves.

If oil and natural gas prices decrease or drilling efforts are unsuccessful, we may be required to take writedowns of our oil and natural gas properties

In the past, we have been required to write down the carrying value of our oil and natural gas properties, and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur when oil and natural gas prices are low or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating and development costs or disappointing drilling results. Such downward adjustments may affect some properties more or less than others.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. Impairment is recognized when the book value of a proven property is greater than the expected undiscounted future cash flows from that property and on acreage when the assessment of fair value is less than the book value. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, as well as a continuing evaluation of development results, production data, economics and other factors. While an impairment charge which reflects our long-term ability to recover on a prior investment does not impact cash flow from operating activities, it reduces our earnings and increases our leverage ratios.

Our business is subject to operating hazards and environmental regulations that could result in substantial losses or liabilities

Oil and natural gas operations are subject to many risks, including 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. If any of these hazards occur, we could sustain substantial losses as a result of injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, and/or suspension of operations.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities for cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue opportunities and place us at a competitive disadvantage. At December 31, 2003, a portion of our borrowings, held through Great Lakes, were subject to interest rate swap agreements, which are above market, and therefore, increase our interest expense.

Our industry is highly competitive

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business, and marketing oil and natural gas. Competitors include major oil companies, independent exploration and production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do.

The oil and natural gas industry is subject to extensive regulation

The oil and natural gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and natural gas industry. Compliance with such rules and regulations often increases our cost of doing business and, in turn, decreases our profitability. Generally these burdens do not appear to affect us to any greater or lesser extent than other companies in the oil and natural gas industry with similar types and quantities of properties in the same areas of the country.

Acquisitions by us are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities

We could be subject to significant liabilities related to acquisitions by us. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties.

However, even a detailed review of all properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel

Our success is highly dependent on our senior management personnel, none of which are currently subject to employment contracts. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical employees is intense. If we cannot retain our current personnel or attract

Table of Contents

additional experienced personnel, our ability to compete could be adversely affected.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from oil and natural gas properties declines as reserves are depleted, our future success depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future oil and natural gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

A portion of our business is subject to special risks related to offshore operation, generally in the Gulf of Mexico

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production. As a result, reserve replacement needs from new prospects are greater and require us to incur significant capital expenditures to replace production.

New technologies may cause our current exploration and drilling methods to become obsolete

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

Our business depends on oil and natural gas transportation facilities, most of which are owned by others

The marketability of our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Our financial statements are complex

Due to new accounting rules, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations and the accounting for the deferred compensation plan. The Company expects such complexity to continue and possibly increase.

Available Information

The Company maintains an internet website under the name www.rangeresources.com . The Company makes available, free of charge, on its website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the Company s Corporate Governance principles, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, the Executive Committee, and the Governance and Nomination Committee, and the Code of Business

Table of Contents

Conduct and Ethics are also available on the website and in print to any stockholder who provides a written request to the Corporate Secretary.

The Company files annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that the Company files with the SEC at the SEC s Public Reference Room at 450 Fifth Street, N.W., Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including the Company, that file electronically with the SEC. The public can obtain any documents the Company files with the SEC at www.sec.gov.

Employees

As of January 1, 2004, the Company had 151 full-time employees, 55 of whom were field personnel. None are covered by a collective bargaining agreement. Management believes its relationship with employees is good.

ITEM 2. PROPERTIES

On December 31, 2003, the Company held working interests in 11,941 gross (6,080 net) productive wells and royalty interests in an additional 227 wells. Including its 50% share of Great Lakes reserves, its properties contained, net to its interest, estimated proved reserves of 486 Bcf of gas and 22 million barrels of oil and 11 million barrels of NGLs or a total of 685 Bcfe.

Proved Reserves

The following table sets forth estimated proved reserves at the end of each of the past five years:

	December 31,				
	2003	2002	2001	2000	1999
Natural gas (Mmcf)					
Developed	344,187	320,224	276,162	305,796	299,437
Undeveloped	142,216	120,043	112,765	121,871	144,346
Total	486,403	440,267	388,927	427,667	443,783
Oil and NGLs (Mbbls)					
Developed	24,912	17,176	14,066	17,215	17,884
Undeveloped	8,111	5,776	6,614	8,787	10,933
Total	33,023	22,952	20,680	26,002	28,817

Total (Mmcfe)[a]	684,541	577,977	513,005	583,679	616,685
% Developed	72.1%	73.2%	70.3%	70.1%	66.0%

[a] Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

At December 31, 2003, 72.1% of the Company s proved reserves by volume were classified as developed and 27.9% were classified as undeveloped. The undeveloped reserves were located 58% in Appalachia, 28% in Southwest and 14% in the Gulf Coast regions.

At year-end 2003, the following independent petroleum consultants reviewed the Company s reserves: DeGolyer and MacNaughton (Southwest and Gulf Coast), H.J. Gruy and Associates, Inc. (Southwest), and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their history in engineering certain properties. At December 31, 2003, these consultants collectively reviewed approximately 87% of the proved reserves. All estimates of oil and gas reserves are subject to uncertainty.

The following table sets forth the estimated future net revenues, excluding open hedging contracts, from proved reserves, the present value of those revenues and the expected realized prices used in projecting them over the past five years (in millions except prices):

	December 31,				
	2003	2002	2001	2000	1999
Future net revenue	$2,687	$1,817	$ 750	$3,764	$1,013
Present Value					
Pretax	1,396	965	399	1,964	556
After tax	1,003	500	311	1,506	503
Oil price (per barrel)	$29.48	$27.52	$17.59	$24.46	$23.49
Gas price (per mcf)	$ 6.03	$ 4.76	$ 2.70	$ 9.57	$ 2.34

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including production taxes and operating expenses). Such calculations, prepared in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, are based on costs and prices in effect at December 31, 2003. Weighted average product prices at December 31, 2003 were $29.48 per barrel of oil, $19.93 per barrel for natural gas liquids, and $6.03 per mcf of gas using benchmark NYMEX prices of $32.52 per barrel and $6.19 per Mmbtu. There can be no assurance that the proved reserves will be produced within the periods indicated and prices and costs will not remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of reserves have been filed with or included in reports to another federal authority or agency since year-end.

Significant Properties

The Company s operations are divided into three geographical divisions known as Southwest, Gulf Coast and Appalachia. The Appalachia division represents the Company s 50% ownership in Great Lakes. At year-end, the Company s properties included working interests in 11,714 (6,080 net) productive oil and gas wells, royalty interests in an additional 227 wells, and 834,000 (376,000 net) undeveloped acres. Of amounts included in the oil and NGL category, 68% is oil. The following tables sets forth summary information by division with respect to estimated proved reserves at December 31, 2003:

	Pretax Present Value		Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 668,489	48	26,175	187,188	344,238	50
Appalachia	489,911	35	5,527	228,427	261,589	39
Gulf Coast	237,416	17	1,321	70,788	78,714	11
Total	$1,395,816	100	33,023	486,403	684,541	100

December 31, 2003

	Southwest	Appalachia	Gulf Coast	Total
Natural gas (Mmcf)				
Developed	163,232	134,000	46,955	344,187
Undeveloped	23,956	94,427	23,833	142,216
Total	187,188	228,427	70,788	486,403
Oil and NGLs (Mbbls)				
Developed	21,195	2,886	831	24,912
Undeveloped	4,980	2,641	490	8,111
Total	26,175	5,527	1,321	33,023
Total (Mmcfe)[a]	344,238	261,589	78,714	684,541

[a] Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

Southwest division

The Southwest division conducts production and field operations in the Permian Basin of West Texas and the East Texas Basin as well as in the Texas Panhandle and the Anadarko Basin of western Oklahoma. This region represents 48% of the Company s total reserves by value and 50% by volume. Proved reserves in the Southwest division totaled 344 Bcfe, of which

54% was gas. Reserves increased 104.6 Bcfe, a 44% increase over 2002 due to purchases, additions, favorable revisions based upon well performance and higher commodity prices. The region s daily production totaled 78.2 Mmcfe per day, representing 49% of total production. On an annual basis, production increased 9% over 2002. At year-end, the Southwest division had an inventory of 166 proven recompletions and 169 proven drilling locations. Acreage owned in the region at that date included 256,000 (194,000 net) developed acres and 154,000 (112,000 net) undeveloped acres. During 2003, 99 (86.4 net) development wells were drilled in the region, of which 85 (76.1 net) were productive and 5 (4.3 net) exploratory wells were drilled, of which 1 (1.0 net) was productive. During the year, the region achieved an 85% drilling success rate.

In West Texas, in the Conger Field of Sterling County, the Company added approximately 86 Bcfe in reserves in 2003. Drilling added 5.9 Bcfe as 12 (11.2 net) wells were drilled, of which 10 (9.2 net) were successful. Another 80 Bcfe in reserves were added in December 2003, when the Company completed an $87.1 million producing property acquisition adjacent to its current operations. The acquisition, which established Range as the largest operator in the field, added 500 operated wells to Range s existing 300 wells. Production from the acquired properties is expected to exceed 22 Mmcfe per day, while total field production is expected to reach 35 Mmcfe per day in 2004. The properties encompass 38,000 (32,000 net) acres and include a 400-mile gathering system. To date, the Company has identified 64 drilling locations and has plans to drill a number of them in 2004. At the Fuhrman-Mascho field in Andrews County, where a waterflood redevelopment project was undertaken in 2002, a total of 27 (26.0 net) producers and 11 (11.0 net) injectors have been successfully drilled. At year-end, the combined daily production rate from the field was approximately 8.5 Mmcfe per day. In total, 2003 drilling added 13 Bcfe in reserves to the field. A response to the waterflood is expected by the end of 2004. Even if the waterflood fails to yield a positive response, primary production has proved to be economic. If the waterflood does yield a positive response, a multi-phase expansion project is planned. At Powell Ranch in Glasscock County, 3 (2.2 net) wells were drilled, of which 1(0.2 net) was successful. At year-end, production from that field totaled 6.9 net Mmcfe per day. In the Val Verde Basin, a recompletion program in 2003 added 1.8 Mmcfe per day to production. In addition, 8 (7.0 net) wells were drilled, of which 6 (5.5 net) were successful. By year-end, production from Range s 202 wells in the Val Verde Basin totaled 14.5 (10.1 net) Mmcfe per day.

In East Texas, the second and third phases of a high-volume lift program were completed in 2003 in the Laura LaVelle field in Houston County. A fourth phase is currently underway. The project is designed to expand the field s water disposal system and facilitate increased pumping capacity. With 13 (12.8 net) shallow wells drilled in the field at average depths of 2,000 feet last year, production increased 18% to 4.4 (4.0 net) Mmcfe per day at year-end. In 2004, there are 3 (3.0 net) exploratory wells planned to test several medium-depth formations including the Wilcox, Woodbine and Buda formations in Houston County, at depths ranging between 6,000 and 11,000 feet. In Tyler County, Range has identified 4 (1.75 net) deeper Woodbine prospects on existing properties. These Woodbine wells target formations at depths in excess of 14,000 feet. In the James Lime trend of East Texas, 3 (2.0 net) wells drilled in 2003, of which 2 (1.5 net) proved successful.

In the Texas Panhandle, the Morrow play in the Texas Panhandle continued to yield significant production and reserve growth for Range in 2003. Drilling success in the area resulted in a net 62% increase in production for the area compared to the previous year-end. Equally important, strategic leasehold purchases during 2003 increased Range s acreage position in the play to 69,000 (52,000 net) acres, adding in excess of 20 potential drilling locations. In addition, the Company has acquired 912 miles of 2-D seismic data covering the field that is currently being processed and interpreted. Range continues to pursue the acquisition of additional acreage in the area. The division drilled 21 (17.7 net) Morrow wells in the Texas Panhandle in 2003, achieving an 84% success rate. The 17 (14.8 net) successful wells are currently producing at a net of 8.6 Mmcfe per day. In 2004, a total of 21 (14.5 net) wells are planned in the area to test various formations including Morrow, Hunton, Woodford and Brown Dolomite.

In the Anadarko Basin, Range drilled a total of 10 (5.6 net) wells in the Watonga-Chickasha trend of the Anadarko Basin, achieving a 98% success rate. The most notable successes were 6 (4.0 net) wells drilled on undeveloped leasehold acquired by Range in late 2002. The net production rate for the six wells at December 2003 was 2.7 Mmcfe per day. A total of 9 (4.3 net) wells are planned in this trend in 2004. The division also has plans in 2004 to test several deeper and higher potential prospects in western Oklahoma.

Gulf Coast division

The Gulf Coast division represents 17% of total Company reserves by value and 11% by volume. Proved reserves totaled 78.7 Bcfe, a decrease of 8% compared to 2002. During the year, the region s production totaled 45.2 Mmcfe per day. Gulf Coast reserves are 90% natural gas. Properties are located in the shallow waters of the Gulf of Mexico and onshore in Texas, Louisiana and Mississippi. The division s wells are characterized by high initial rates and relatively short reserve lives. Production by the Gulf Coast division represented 28% of the Company s total. Major onshore fields produce from Hartburg formations at depths of 10,000 to 11,000 feet in the Upper Texas Gulf Coast to the Upper Oligocene in South

Louisiana at depths of 10,000 to 12,000 feet to the Sligo and Hosston formations at depths of 15,000 to 16,500 feet in the Oakvale field in Mississippi. Range operates a majority of its onshore properties while third parties operate its offshore properties. Offshore properties include interests in 37 platforms in water depths ranging from 11 to 240 feet. The Gulf Coast s development inventory includes 34 recompletions and 13 drilling locations on 129,000 (43,000 net) developed acres and 54,000 (14,000 net) undeveloped acres.

In 2003, the region spent $20.1 million to drill 4 (1.7 net) wells, recomplete 12 (3.6 net) others and to upgrade facilities. In the fourth quarter of 2003, net production averaged 647 barrels of oil and 42.4 Mmcf of gas per day or 46.2 Mmcfe per day in total. Production during the year increased 1% to 45.2 Mmcfe per day, reversing a 22% decrease in production from the previous year. With minimal drilling in 2003 and no acquisitions, the division replaced only 58% of production. During 2003, 1 development well (0.5 net) was drilled, which was productive. Three exploratory wells (1.2 net) were drilled with 2 (1.1 net) proving productive.

No new offshore wells were drilled in 2003, but work progressed to set up several significant wells for 2004 drilling. The joint venture formed between Range and two other companies continued to explore the central shelf of the Gulf of Mexico. Since forming the joint venture in 2001, $3.1 million has been spent on seismic data. The joint venture increased its total 3-D seismic data coverage from 6,100 square miles to 6,250 square miles in 2003 and the joint technical team continues to work the data, with a total number of 43 identified prospects. The joint venture continues to pursue leases and farm-ins to capture these leads and successfully secured leases in the March 2003 government sale that will allow for 2004 drilling of 2 (0.3 net) exploration wells. Range owns a 14% working interest in both prospects, which are on trend with other producers. The joint venture also secured a farm-in that will drill in the first half of 2004. Range owns a 10.5% working interest in this prospect.

Outside of the joint venture, Range is participating in 3 (0.8 net) offshore wells in the first quarter of 2004. The Chandeleur 17 S/L 17619#1 and the High Island 111 A-10 Sidetrack both reached total depth and set production casing in January, with production expected in March. The West Cameron 56 #17, an initial offset to the Company s 2002 West Cameron discovery, began drilling in January. If successful, this fault-separated offset could prove up two additional locations. In addition, the Falcon Prospect, located on East Cameron Block 33, is scheduled to spud later in 2004. This high risk/high reward project exposes Range to significant reserves at a potential net dry hole cost of $2.6 million. The Company retains a 25% working interest to casing point and a 37% working interest after casing point. Finally, Range has partnered with ExxonMobil licensing a portion of their 3-D seismic shoot of the old West Delta #30 field. Range has identified several leads. The first development location, a sidetrack, is scheduled to drill in the first quarter of 2004. Range retains a 49% interest in the field.

Onshore, Range had a successful year, increasing onshore production by 16%. Using state-of-the-art seismic technology to reprocess 3-D data and through skillful interpretation of subtle reflectors, the technical team successfully identified and drilled several high-rate producers. The team will attempt to replicate their success utilizing 500 square miles of reprocessed 3-D seismic covering onshore south Louisiana to search for additional opportunities overlooked with predecessor technologies.

Following up on a Marg howei discovery well drilled in south Louisiana in late 2002, 2 (0.9 net) additional wells were successfully drilled in 2003. All three wells have been prolific producers, with cumulative total production through year-end of 6.6 (2.1 net) Bcfe. Another South Louisiana well, the Hubbard #1, a 14,000 foot Nonion Struma test, spud in November and is currently drilling. Range has a 21% working interest in the prospect. In addition, 1 (0.6 net) well is planned in the South Louisiana area in the first quarter of 2004. In the Gulf Coast area, Range had exploration success with another seismically defined prospect. Range drilled a 14,500 foot well in late 2003, encountering 55 net feet of pay. Range owns 68% working interest in the well, which recently tested at 7.4 (3.7 net) Mmcfe per day with reservoir pressure of 9,300 pounds. Finally, one Vicksburg exploration well, in which Range owned a 10% working interest, was drilled in Orange County and proved unproductive. The Gulf Coast 2004 drilling program includes the drilling of 13 (3.7 net) offshore wells and 5 (2.4 net) onshore wells.

Appalachian division

Through its 50% interest in Great Lakes, the Appalachia division represents 262 Bcfe of proved reserves, or 39% by volume and 35% by value of total proved reserves. The region has a working interest in 9,175 gross (4,096 net) wells and approximately 5,000 miles of gas gathering lines. At December 31, 2003, Great Lakes had an inventory 1,701 proven drilling locations and of 52 proven recompletions.

	Development Projects		
	Drilling Locations	Recompletion Opportunities	Total
Beginning of 2003	1,665	68	1,733
Drilled	(143)		(143)
Added	279		279
Deleted & other	(100)	(16)	(116)
End of 2003	1,701	52	1,753

Acreage owned in the Appalachian region at December 31, 2003 included 869,000 (415,000 net) developed acres and 627,000 (249,000 net) undeveloped acres. During 2003, 238 (105.1 net) development wells were drilled, of which 236 (104.1 net) were productive. Twelve (2.8 net) exploratory wells were drilled, of which 8 (1.8 net) were productive. At December 31, 2003, Great Lakes operated 99% of its wells. The reserves are 87% gas and produce principally from the Upper Devonian, Medina, Clinton, Knox and Oriskany formations at depths ranging from 2,500 to 7,000 feet. For the year, net daily production averaged 30.6 Mmcfe of gas and 852 barrels of oil, or a total of 35.7 Mmcfe per day. The division s properties, with 1,753 proven projects at year-end, are located in the Appalachian and, to a minor extent, the Michigan Basins of the northeastern United States. After initial flush production, these properties are characterized by gradual decline rates, producing on average for 10 to 35 years.

In 2003, $20.9 million in capital funded the drilling of 238 (105.1 net) shallow development wells, 9 (2.2 net) medium depth exploration wells and 3 (0.6 net) deep exploration wells. In addition, capital was expended on one (0.5 net) recompletion as well as the purchase of 219 miles of seismic data and 258,000 (86,000 net) acres of leasehold. Of the 238 development wells drilled, 236 were successful. Eight of the 12 exploration wells were also successful, indicating an overall 98% success rate. Year-end proved reserves increased approximately 4% to 262 Bcfe as a result of acquisitions, additions and higher commodity prices.

The majority of the division s drilling expenditures are directed toward two large shallow-development plays which include the Clinton-Medina and Upper Devonian sandstone trends. In 2003, Great Lakes drilled 156 (68.3 net) wells in the Clinton-Medina and 70 (31.0 net) wells in the Upper Devonian shallow plays with an overall success rate of 99%. Approximately 89% of the division s capital budget will target shallow drilling in 2004, funding the drilling of 157 (68.2 net) Clinton-Medina wells and 88 (44.0 net) Upper Devonian wells.

In 2003, the division focused on expanding its shallow play development areas. A total of 18 (9.0 net) wells were drilled to test five new shallow development areas. Fifteen (8.0 net) of the test wells were successful, resulting in the extension of two existing fields and establishing at least three new development areas. To date, as many as 40 potential drill sites have been identified in the new development plays. Continued testing of the new areas, as well as leasing activity is planned in 2004.

Approximately 11% of the division s 2003 capital budget targeted both developmental and exploratory drilling to medium and deep plays. In 2003, a total of 12 (2.8 net) exploratory wells were drilled to medium/deep targets, of which 8 (1.8 net) were successful. Highlights include a Trenton-Black River discovery in New York that establishes a new field in an area where the Company owns 50,000 (25,000 net) acres. The well is currently shut-in awaiting pipeline connection. In addition, 2 (0.6 net) Oriskany sandstone discoveries were made in southwestern and north central Pennsylvania. These wells are currently shut-in awaiting pipeline connection or are producing under restricted pipeline conditions. In 2004, the Company plans to drill 14 (4.7 net) exploratory wells, including 5 (1.1 net) to the Trenton-Black River trend, 3 (0.8 net) of which have anticipated well depths above 4,500 feet.

Table of Contents

Production

The following table sets forth total Company production and related information for the past five years (in thousands, except average sales price and operating cost data).

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Production					
Gas (Mmcf)	43,510	41,096	42,278	41,039	50,808
Crude oil (Mbbl)	2,023	1,873	1,916	2,035	2,247
Natural gas liquid (Mbbl)	401	407	326	363	412
Total (Mmcfe)[b]	58,053	54,772	55,730	55,427	66,762
Revenues					
Gas	$171,291	$144,030	$154,175	$118,977	$108,115
Crude oil	47,599	41,665	49,033	47,414	33,075
Natural gas liquids	7,512	5,259	5,646	6,691	4,302
Transportation and gathering	3,509	3,495	3,435	5,306	7,770
Total	229,911	194,449	212,289	178,388	153,262
Direct operating expenses[a]	49,317	40,443	43,430	40,552	43,074
Gross margin	$180,594	$154,006	$168,859	$137,836	$110,188
Average sales price (excluding hedging)					
Gas (per mcf)	$ 5.10	$ 3.02	$ 3.91	$ 3.71	$ 2.24
Crude oil (per bbl)	28.42	23.34	23.34	28.15	16.21
Natural gas liquid (per bbl)	18.75	12.93	17.33	18.43	10.44
Total (per mcfe)[b]	4.94	3.16	3.87	3.90	2.34
Average sales price (including hedging)					
Gas (per mcf)	$ 3.94	$ 3.50	$ 3.66	$ 2.90	$ 2.13
Crude oil (per bbl)	23.53	22.25	25.55	23.30	14.72
Natural gas liquids (per bbl)	18.75	12.93	17.33	18.43	10.44
Total (per mcfe)[b]	3.90	3.49	3.75	3.12	2.18
Operating costs (per mcfe)					
Direct	$ 0.68	$ 0.63	$ 0.67	$ 0.62	$ 0.58
Severance and production taxes	0.17	0.11	0.11	0.11	0.07

Total	$ 0.85	$ 0.74	$ 0.78	$ 0.73	$ 0.65

(a) Includes severance, production and ad valorem taxes.

(b) Oil and NGLs are converted to mcfe at a rate of 6 mcf per barrel.

Table of Contents

Producing Wells

The following table sets forth information (including the Company s 50% share of Great Lakes) relating to productive wells at December 31, 2003. The Company owns royalty interests in an additional 227 wells. Wells are classified as oil or gas according to their predominant production stream.

	Wells		Average Working Interest
	Gross	Net	
Crude oil	2,290	1,574	69%
Natural gas	9,651	4,506	47%
Total	11,941	6,080	51%

Acreage

The following table sets forth acreage held at December 31, 2003.

	Acres		Average Working Interest
	Gross	Net	
Developed	1,254,542	651,754	52%
Undeveloped	833,876	375,838	45%
Total	2,088,418	1,027,592	49%

Drilling Results

The following table summarizes drilling activity for the past three years.

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	322.0	180.7	294.0	162.3	256.0	112.9
Dry	16.0	11.4	6.0	4.1	8.0	5.5
Exploratory wells						

Productive	11.0	3.8	17.0	6.9	6.0	1.9
Dry	9.0	4.4	11.0	5.3	2.0	0.9
Total wells						
Productive	333.0	184.5	311.0	169.2	262.0	114.8
Dry	25.0	15.8	17.0	9.4	10.0	6.4
Total	358.0	200.3	328.0	178.6	272.0	121.2
Success ratio	93%	92%	95%	95%	96%	95%

17

Table of Contents

Real Property

The Company leases approximately 70,000 square feet of office space primarily in Texas and Oklahoma under standard office lease arrangements that expire at various dates through September 2007. All facilities are believed adequate to meet the Company s current needs and existing space could be expanded or additional space could be leased if required. The Company owns various vehicles and other equipment that are used in its field operations. Such equipment is believed to be in good repair and can be readily replaced if necessary.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various legal actions and claims arising in the ordinary course of business, which includes a royalty owner suit filed in 2000 asking for class action certification against Great Lakes and the Company. Through 2003, total cumulative legal costs associated with the Great Lakes class action were $750,000. During 2003, approximately $450,000 of costs were incurred in defense of litigation. In the opinion of management, such litigations and claims are likely to be resolved without a material adverse effect on the Company s financial position or results of operations.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2003.

PART II

ITEM 5. MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES

The Company s common stock is listed on the New York Stock Exchange (NYSE) under the symbol RRC. During 2003, trading volume averaged 179,500 shares per day. The following table sets forth the quarterly high and low sales prices and volumes as reported on the NYSE composite tape for the past two years.

	High	Low	Average Daily Volume
2002			
First quarter	$5.45	$4.03	155,882
Second quarter	5.91	4.95	160,475
Third quarter	5.68	4.05	145,836
Fourth quarter	5.96	4.05	108,856
2003			
First quarter	$6.20	$5.00	136,836
Second quarter	7.43	5.60	185,490
Third quarter	7.35	5.98	161,659

Fourth quarter	9.86	6.80	232,230

Between January 1, 2004 and February 26, 2004, the common stock traded at prices between $9.38 and $11.28 per share. The Company s 7.375% Notes, 6% Debentures, and 5.90% cumulative convertible preferred stock (the Convertible Preferred) are not listed on an exchange, but trade over-the-counter.

Historically, the Company has issued common stock in exchange for debt and convertible securities. Shares of common stock issued in such exchanges were exempt from registration under Section 3(a)(9) of the Securities Act of 1933. The following table summarizes those exchanges for the past three years:

Table of Contents

	Face Amount ($000)			Common Stock Issued (000 s)		
Security Exchanged	2003	2002	2001	2003	2002	2001
8.75% Notes	$	$ 875	$ 3,385		175	754
6% Debentures	880	7,140	5,710	125	1,150	745
Trust Preferred Securities		2,400	2,850		283	291
$2.03 Preferred stock			5,425			767
	$880	$10,415	$17,370	125	1,608	2,557
Market value at date of exchange				$735	$8,242	$14,207

In September 2003, the Company exchanged $10.2 million in cash and $50.0 million of the newly issued Convertible Preferred for $79.5 million of the Trust Preferred Securities held by the largest holder of the Trust Preferred Securities. The exchange, including the issuance of the Convertible Preferred was exempt from registration under Section 3(a)(9) of the Securities Act.

Holders of Record

At February 26, 2004, there were approximately 2,800 holders of record of the common stock.

Dividends

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The Senior Credit Facility and the 7.375% Notes allow for the payment of common and preferred dividends, with certain limitations. The Convertible Preferred is entitled to receive cumulative quarterly dividends at an annual rate of $2.95 per share. In December 2003, the Company announced it would begin paying cash dividends on its common stock at a quarterly dividend rate of one cent per share. The first dividend was paid on January 30, 2004.

Equity Compensation Plans

The following table summarizes securities issuable and authorized by the stockholders under certain equity compensation plans [(a)]:

	Number of Securities to be issued upon exercise of outstanding options	Weighted average exercise price of outstanding options	Number of securities authorized for future issuance under equity compensation plans

Equity compensation plans approved by security holders[b]	3,831,135	$ 5.00	5,107,437

[a] Although the Company does not maintain a formal plan, common stock is issued to officers and key employees in lieu of cash for bonuses and company matches under the Company s deferred compensation arrangements as elected by employees. All such issuances are approved by the Compensation Committee, which is composed of three independent directors. Issuances to Named Employees are disclosed in the Company s proxy statements.

[b] There are no equity compensation plans that have not been approved by security holders.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information for each of the last five years (in thousands, except per share data).

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Balance sheet position at year-end:					
Current assets[(a)]	$ 66,092	$ 50,619	$ 77,735	$ 62,886	$ 77,521
Current liabilities[(b)]	106,964	67,206	47,879	53,221	57,441
Oil and gas properties, net	723,382	564,406	533,357	553,173	570,643
Total assets	830,091	658,484	682,462	671,826	732,228
Senior debt	178,200	115,800	95,000	89,900	140,000
Non-recourse debt	70,000	76,500	98,801	113,009	142,520
Subordinated debt	109,980	90,901	108,690	162,550	176,360
Trust preferred securities		84,840	89,740	92,640	117,669
Stockholders equity[(c)]	274,066	206,109	235,621	159,944	103,238
Weighted average dilutive shares outstanding	57,850	54,418	51,265	42,932	36,933

(a) 2001 includes a hedging asset of $37.2 million.

(b) 2003 and 2002 include hedging liabilities of $54.3 million and $2.6 million, respectively.

(c) Stockholders equity includes other comprehensive income (loss) of ($42.9 million), ($21.2 million), $45.5 million, ($639,000) and $189,000 in 2003, 2002, 2001, 2000 and 1999, respectively.

Table of Contents

Operations:

	Year Ended December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
Revenues					
Oil and gas sales	$226,402	$190,954	$208,854	$173,082	$145,492
Transportation and gathering	3,509	3,495	3,435	5,306	7,770
IPF income	1,547	3,789	6,646	7,162	8,513
Gain on retirement of securities	18,991	3,098	3,951	17,763	2,430
Other	(1,252)	(2,900)	490	(722)	343
Gain on formation of Great Lakes					30,929
	249,197	198,436	223,376	202,591	195,477
Expenses					
Direct operating	36,423	31,869	34,884	32,457	37,401
Production and ad valorem taxes	12,894	8,574	8,546	8,095	5,673
IPF	2,965	6,847	3,761	1,974	6,389
Exploration	13,946	11,525	5,879	3,187	2,409
General and administrative	24,377	17,240	12,212	14,953	8,793
Interest expense and dividends on trust preferred	22,165	23,153	32,179	39,953	47,085
Debt conversion expense	465				
Depletion, depreciation and amortization	86,549	76,820	77,573	66,968	80,598
Provision for impairment			31,085		29,901
	199,784	176,028	206,119	167,587	218,249
Income (loss) before income taxes and accounting change	49,413	22,408	17,257	35,004	(22,772)
Income tax (benefit)					
Current	170	(4)	(406)	(1,574)	770
Deferred	18,319	(3,354)			
	18,489	(3,358)	(406)	(1,574)	770
Income before cumulative effect of change in accounting principle	30,924	25,766	17,663	36,578	(23,542)
Cumulative effect of change in accounting principle, net of taxes	4,491				
Net income (loss)	35,415	25,766	17,663	36,578	(23,542)

Gain on retirement of preferred stock			556	5,966	
Preferred dividends	(803)		(10)	(1,554)	(2,334)
Net income available to common shareholders	$ 34,612	$ 25,766	$ 18,209	$ 40,990	$ (25,876)
Net income (loss) available to common shareholders	$ 0.56	$ 0.49	$ 0.36	$ 0.97	$ (0.71)
Cumulative effect of change in accounting principle	0.08				
Net income (loss) per common share	$ 0.64	$ 0.49	$ 0.36	$ 0.97	$ (0.71)
Earnings per common share assuming dilution	$ 0.53	$ 0.47	$ 0.36	$ 0.96	$ (0.71)
Cumulative effect of change in accounting principle	0.08				
Net income (loss) per common share assuming dilution	$ 0.61	$ 0.47	$ 0.36	$ 0.96	$ (0.71)

Table of Contents

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years (in thousands, except per share data).

	2002				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$44,283	$48,626	$48,112	$49,933	$190,954
Transportation and gathering	774	924	1,037	760	3,495
IPF income	1,171	992	1,313	313	3,789
Gain on retirement of securities	1,185	845	1,050	18	3,098
Other	(2,009)	(1,235)	(125)	469	(2,900)
	45,404	50,152	51,387	51,493	198,436
Expenses					
Direct operating					