RANGE RESOURCES CORP
Form 10-K
February 27, 2008

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

(Mark one)

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

For the fiscal year-ended December 31, 2007

or

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

For the transition period from__________ to __________

Commission file number 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**34-1312571**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s Telephone Number, Including Area Code
(817) 870-2601
Securities registered 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 if the registrant as a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

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 a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

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 29, 2007 was $5,459,435,000.

As of February 20, 2008, there were 149,903,625 shares of Range Resources Corporation Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant s proxy statement to be furnished to stockholders in connection with its 2008 Annual Meeting of Stockholders are incorporated by reference in Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to Range we us or our are to Range Resources Corporation and its wholly-owned subsidiaries and its ownership interests in equity method investees. Unless otherwise noted, all information in the report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption Glossary of Certain Defined Terms at the end of Item 15 of this report.

TABLE OF CONTENTS

Table of Contents

RANGE RESOURCES CORPORATION
Annual Report on Form 10-K
Year Ended December 31, 2007

Disclosures Regarding Forward-Looking Statements

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission (the SEC), as well as information included in oral statements or other written statements made or to be made by us 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, shoul goal, anticipates, expects, believes, seeks, plans, estimates, intends, projects or targets and similar 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: the factors listed in Item 1A of this report under the heading Risk Factors, 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 we undertake no obligation to publicly update or revise any forward-looking statements.

PART I

ITEM 1. BUSINESS

General

We are a Fort Worth, Texas-based independent oil and gas company, engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We were incorporated in early 1980 under the name Lomak Petroleum, Inc. and, later that year, we completed an initial public offering and began trading on the NASDAQ. In 1996, our common stock was listed on the New York Stock Exchange. In 1998, we changed our name to Range Resources Corporation. In 1999, we implemented a strategy of internally generated drillbit growth coupled with complementary acquisitions. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. During the past five years, we have increased our proved reserves 286%, while production has increased 115% during that same period.

At year-end 2007, our proved reserves had the following characteristics:

- 2.2 Tcfe of proved reserves;
- 82% natural gas;
- 64% proved developed;
- 77% operated;
- a reserve life of 17.7 years (based on fourth quarter 2007 production);

- a pre-tax present value of $5.2 billion of future net revenues attributable to our reserves, discounted at 10% per annum (PV-10); and

- a standardized measure of discounted future net cash flows of $3.7 billion (after tax).

PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is discounted estimated future income tax of $1.5 billion at December 31, 2007.

At year-end 2007, we owned 3,385,000 gross (2,695,000 net) acres of leasehold, including 407,800 acres where we also own a royalty interest. We have built a multi-year inventory drilling that is estimated to contain over 11,000 drilling locations, with approximately 8,500 drilling locations in our Appalachian region.

Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our telephone number is (817) 870-2601.

Business Strategy

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy is to employ internally generated drillbit growth coupled with complementary acquisitions. Our strategy requires us to make significant investments in technical staff, acreage and seismic data and technology to build drilling inventory. Our strategy has the following principal elements:

Concentrate in Core Operating Areas. We currently operate in three regions; the Southwestern (which includes the Barnett Shale of North Central Texas, the Permian Basin of West Texas and eastern New Mexico, the East Texas Basin, the Texas Panhandle and Anadarko Basin of Western Oklahoma), Appalachian (which includes tight-gas, shale, coal bed methane and conventional oil and gas production in Pennsylvania, Virginia, Ohio, New York and West Virginia) and the Gulf Coast (which includes onshore Texas, Louisiana and Mississippi). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale. Operating in multiple core areas allows us to blend the production characteristics of each area to balance our portfolio toward our goal of consistent production and reserve growth.

Maintain Multi-Year Drilling Inventory. We focus on areas where multiple prospective productive horizons and development opportunities exist. We use our technical expertise to build and maintain a multi-year drilling inventory. A large, multi-year inventory of drilling projects increases our ability to consistently grow production and reserves. Currently, we have over 11,000 identified drilling locations in inventory. In 2007, we drilled 967 gross (698 net) wells. In 2008, our capital program targets the drilling of 968 gross (715 net) wells.

Make Complementary Acquisitions. We target complementary acquisitions in existing core areas and focus on acquisition opportunities where our existing operating and technical knowledge is transferable and drilling results can be forecast with confidence. Over the past three years, we have completed $903.8 million of complementary acquisitions. These acquisitions have been located in the Southwestern and Appalachian regions.

Maintain Long Life, Low Decline Reserve Base. Long life, low decline, oil and gas reserves provide a more stable growth platform than short life, high decline reserves. Long life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long life, low decline oil and gas reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Lastly, the inherent greater predictability of low decline oil and gas reserve production better lends itself to commodity price hedging than high decline reserves. We use our acquisition, divestiture, and drilling activity to execute this strategy.

Maintain Flexibility. Because of the volatility of commodity prices and the risks involved in drilling, we remain flexible and adjust our capital budget throughout the year. We may defer capital projects to seize an attractive acquisition opportunity. If certain areas generate higher than anticipated returns, we may accelerate drilling in those areas and decrease capital expenditures elsewhere. We also believe in maintaining a strong balance sheet and using commodity hedging. This allows us to be more opportunistic in lower price environments as well as providing more consistent financial results.

Equity Ownership and Incentive Compensation. We want our employees to act like owners. To achieve this, we reward and encourage them through equity ownership in us. As of December 31, 2007, our employees owned equity securities (vested and unvested) that had an aggregate market value of approximately $260 million.

Table of Contents

Significant Accomplishments in 2007

Production and reserve growth The fourth quarter of 2007 marked the 20th consecutive quarter of sequential production growth. In 2007, our annual production averaged 319.0 Mmcfe per day, an increase of 22% from 2006, after reclassification of 2006 to report the results of the Gulf of Mexico properties sold in the first quarter of 2007 as discontinued operations. See Note 4 to our consolidated financial statements. This achievement is the result of our continued drilling success and the completion and integration of complementary acquisitions. Our business is inherently volatile, and while consistent growth such as we have experienced over the past five years will be challenging to sustain, the quality of our technical teams and our sizable drilling inventory bode well for the future. Proven reserves increased 27% in 2007 to 2.2 Tcfe, marking the sixth consecutive year our proven reserves have increased.

Successful drilling program In 2007, we drilled 967 gross wells. Production was replaced by 416% through drilling in 2007, and our overall success rate was 98%. As we continue to build our drilling inventory for the future, our ability to drill a large number of wells each year on a cost effective and efficient basis is critical.

Continued expansion of drilling inventory and emerging plays To continue to grow, the size of our prospect inventory must remain large. Our drilling inventory currently includes over 11,000 projects, up from 9,400 at year-end 2006. We engaged in meaningful expansion of our coal bed methane plays and our shale plays in 2007. We have now leased 286,000 net acres in our coal bed methane plays and 1.0 million net acres in our shale plays. We have hired additional experienced technical professionals to assist us in these emerging plays.

Record financial results and balance sheet enhancement Growth in production volumes and higher oil and gas prices drove our record financial performance in 2007. Revenue, net income, and net cash flow provided from operating activities all reached annual record highs. On the balance sheet, we refinanced $250 million of shorter term bank debt with a like amount of senior subordinated fixed rate 7.5% notes having a 10-year maturity. This helped to align the maturity schedule of our debt with the long-term life of our assets. Financial leverage, as measured by the debt-to-capitalization ratio improved from 46% to 40%. Future cash flow will be enhanced through low income tax payments due to a $204.4 million net operating loss carryforward.

Successful acquisitions completed In 2007, we acquired $260.9 million of properties located in our core areas. The largest acquisition involved acquiring additional interests in the Nora field of Virginia, where we entered into a joint development plan with Equitable Resources, Inc. (Equitable). As a result of this transaction, Equitable and Range equalized their working interests in the Nora field, including producing wells, undrilled acreage and gathering systems. Range retained separately owned royalty interests in the field. Equitable operates the producing wells, manages the drilling operations of all future coal bed methane wells and manages the gathering system. Range oversees the drilling of formations below the coal bed methane formations, including tight gas, shale and deeper formations. A newly formed limited liability company, owned 50% by Equitable and 50% by Range, holds the investment in the gathering system.

Successful dispositions completed In February 2007, we sold the Austin Chalk properties for proceeds of $80.4 million. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. As a result of these divestitures, we lowered our overall production decline rate and lengthened our reserve life. See Note 4 to our consolidated financial statements.

Plans for 2008

We have announced a $1.1 billion capital budget for 2008, excluding acquisitions. The budget includes $783 million to drill 968 gross (715 net) wells and to undertake 82 gross (66 net) recompletions. Also included is $109 million for land, $51 million for seismic and $122 million for the expansion and enhancement of gathering systems and facilities. Approximately 56% of the budget is attributable to the Southwest Area, 40% to the Appalachia Area and 4% to the Gulf Coast Area.

Table of Contents

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production, revenues and direct operating expenses for the last three years. The information set forth in this table reflects the reclassification of prior year amounts to report the results of operations of our Gulf of Mexico properties sold in the first quarter of 2007 as discontinued operations. For additional information on price calculations, see information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,		
	2007	2006	2005
Production			
Gas (Mmcf)	89,595	70,713	57,609
Crude oil (Mbbls)	3,360	3,039	2,929
Natural gas liquids (Mbbls)	1,115	1,092	1,012
Total (Mmcfe) [(a)]	116,441	95,498	81,253
Revenues ($000)			
Gas	$ 613,454	$ 418,183	$ 354,728
Crude oil	202,931	144,251	113,153
Natural gas liquids	46,152	36,705	27,589
Transportation and gathering	2,290	2,422	2,306
Derivative fair value income (loss)	(7,767)	142,395	10,303
Less: Mark-to-market component of derivative fair value income (loss) [(c)]	79,589	(92,456)	(7,397)
Total	936,649	651,500	500,682
Direct operating expenses [(b)]	108,741	81,261	57,866
Production and ad valorem taxes	42,443	36,415	30,822
Gross margin	$ 785,465	$ 533,824	$ 411,994
Average sales price (wellhead)			
Gas (per mcf)	$ 6.54	$ 6.59	$ 8.00
Crude oil (per bbl)	67.47	62.36	53.30
Natural gas liquids (per bbl)	41.40	33.62	31.52
Total (per mcfe) [(a)]	7.37	7.25	7.99
Average realized price (including all derivative settlements)			
Gas (per mcf)	$ 7.66	$ 6.62	$ 6.21
Crude oil (per bbl)	60.16	47.46	38.63
Natural gas liquids (per bbl)	41.40	33.62	27.27
Total (per mcfe) [(a)]	8.02	6.80	6.13
Operating costs (per mcfe)			
Direct [(b)]	$ 0.93	$ 0.85	$ 0.71
Production and ad valorem taxes	0.36	0.38	0.38
Total operating costs	$ 1.29	$ 1.23	$ 1.09

Gross margin (per mcfe)	$ 6.74	$ 5.59	$ 5.07

(a) Oil and NGLs are converted at the rate of one barrel equals six mcfe.

(b) 2007 direct operating expenses include $1.8 million (or $0.02 per mcfe) of stock-based compensation. 2006 direct operating expenses include $1.4 million (or $0.01 per mcfe) of stock-based compensation.

(c) By adding this component, the total reflects realized gains (losses) on those derivatives that do not qualify for hedge accounting and excludes unrealized gains (losses) on derivatives that do not qualify for hedge accounting.

Employees

As of January 1, 2008, we had 733 full-time employees, 371 of whom were field personnel. All full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field, on-site production operation services and certain accounting functions.

Available Information

We maintain an internet website under the name www.rangeresources.com. We make available, free of charge, on our 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, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, and the Governance and Nominating Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the chief executive officer and senior financial officers.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, 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 Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Competition

We encounter substantial competition in developing and acquiring oil and gas properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independent oil companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. 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 our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling.

Marketing and Customers

We market nearly all of our oil and gas production from the properties we operate for both our interest and that of the other working interest owners and royalty owners. We sell our gas pursuant to a variety of contractual arrangements; generally month-to-month and one to five-year contracts. Less than 1% of our production is subject to contracts longer than five years. Pricing on the month-to-month and short-term contracts is based largely on the New York Mercantile Exchange (NYMEX) pricing, with fixed or floating basis. For one to five-year contracts, we sell our gas on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on local indices. We sell less than 500 mcf per day under long-term fixed price contracts. Many contracts contain provisions for periodic price adjustment, termination and other terms customary in the industry. We sell our gas to utilities, marketing companies and industrial users. We sell our oil under contracts ranging in terms from month-to-month, up to as long as one year. The pricing for oil is based upon the posted prices set by major purchasers in the production area or upon NYMEX pricing or fixed pricing. All oil pricing is adjusted for quality and transportation. Oil and gas purchasers are selected on the basis of price, credit quality and service. For a summary of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue, see Note 15 to our consolidated financial statements. Because alternative purchasers of oil and gas are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

We enter into hedging transactions with unaffiliated third parties for significant portions of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, see the information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices for which our production can be sold. Market volatility due to international political developments, overall energy supply and demand, fluctuating weather conditions, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We incur gathering and transportation expenses to move our natural gas and crude oil from the wellhead and tanks to purchaser specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party transporters. In the Southwestern and Gulf Coast Areas, our natural gas and oil production are transported primarily through third-party trucks, gathering systems and pipelines. Transportation space on these gathering systems and pipelines is occasionally limited. In Appalachia, we own approximately 5,100 miles of gas gathering pipelines which transport a majority

Table of Contents

of our Appalachian gas production as well as third-party gas to transmission lines and directly to end-users and interstate pipelines. For additional information, see Risk Factors *Our business depends on oil and natural gas transportation facilities, many of which are owned by others*, in Item 1A of this report.

Governmental Regulation

Our 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. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individuals wells.

In August 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Among other matters, the EPAct 2005 amends the Natural Gas Act (NGA), to make it unlawful for any entity , including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (FERC), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC s enforcement authority. Range does not anticipate it will be affected any differently than other producers of natural gas.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance.

Additional proposals and proceedings that affect the oil and gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

Environmental and Occupational Matters

Our 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 United States 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 administrative, 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 or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits and impose substantial liabilities for pollution resulting from operations. In addition, these laws and regulations may restrict the rate of production. The regulatory burden imposed on the oil and gas industry by these laws and regulations 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 our operations and financial position, as well as the industry in general. We believe we are in substantial compliance with current applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2007, nor do we anticipate that such expenditures will be material in 2008.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, (CERCLA), known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include owners or operators 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 and 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 pursuant to environmental statutes, common law or both. Although petroleum, including crude oil and natural gas, is not a hazardous substance under 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 therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA. Beyond CERCLA, state laws regulate the disposal of oil and gas wastes, and periodically new state legislative initiatives are proposed that could have a significant impact on us.

We also may incur liability under the Resource Conservation and Recovery Act, as amended (RCRA), which imposes requirements related to the handling and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy, these wastes may be regulated by the EPA or state agencies as non-hazardous 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 wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act, as amended (FWPCA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the state. These laws provide for administrative, civil and criminal 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. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of greater than threshold quantities of oil. We are currently undertaking a review of recently acquired oil and gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will have a material adverse affect on our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is actively considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman Warner Climate Security Act or S. 2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. A vote on this bill by the full Senate is expected to occur before mid-year 2008. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address greenhouse gas emissions from vehicles and automobile fuels, although the date for the issuance of this notice has not been finalized. The Court s holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our products.

We are also subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes some, but not all, of the risks and uncertainties which may adversely affect our business, financial condition or results of operations.

Risks Related to Our Business

Volatility of oil and natural gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically

Oil and natural gas prices are volatile, and a decline in prices would adversely affect our profitability and financial condition. The oil and natural gas industry is typically cyclical, and prices for oil and natural gas have been highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. Higher oil and natural gas prices have contributed to our positive earnings over the last several years. However, long-term supply and demand for oil and natural gas is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of oil and gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Decreases in oil and natural gas prices from current levels could adversely affect our revenues, net income, cash flow and proved reserves. Significant 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 would be unable to replace reserves and production.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, utilizing commodity derivatives with respect to a significant portion of our future production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if oil and natural gas prices rise above the price established by the hedge.

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 futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices or the relationship between the hedged price index and the oil and gas sales price.

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 reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and natural gas that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of oil and natural gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of oil and natural gas production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net revenues from our proved reserves included in this Report should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based generally on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

If oil and natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record write-downs of our oil and natural gas properties

In the past, we have been required to write down the carrying value of certain of our oil and natural gas properties, and there is a risk that we will be required to take additional write-downs in the future. This could 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 or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair does not justify the expense.

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 net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. 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 drilling results, production data, economics and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Our business is subject to operating hazards and environmental regulations that could result in substantial losses or liabilities that may not be fully covered under our insurance policies

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 natural 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; or

suspension of operations.

As we drill to deeper horizons and in more geologically complex areas, we could experience a greater increase in operating and financial risks due to inherent higher reservoir pressures and unknown downhole risk exposures. As we continue to drill deeper, the number of rigs capable of drilling to such depths will be fewer and we may experience greater competition from other operators.

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. Recently, we have experienced substantial increases in premiums especially in areas affected by the hurricanes and tropical storms. Insurers have imposed revised limits affecting how much the insurers will pay on actual storm claims plus the cost to re-drill wells where substantial damage has been incurred. Insurers are also requiring us to retain larger deductibles and reducing the scope of what insurable losses will include. Even with the increase in future insurance premiums, coverage will be reduced, requiring us to bear a greater potential risk if our oil and gas properties are damaged. We do not maintain any business interruption insurance. 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 acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example at December 31, 2007, approximately 74% of our debt is at fixed interest rates with the remaining 26% subject to variable interest rates. Recent unfavorable disclosures concerning the sub-prime mortgage market may lead to a contraction in credit availability impacting our ability to finance our operations.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

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 multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can.

The demand for field services and their ability to meet that demand may limit our ability to drill and produce our oil and natural gas properties

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This is causing escalating prices, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. In some cases, we are operating in new areas where services and infrastructure do not exist or in urban areas which are more restrictive.

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.

Table of Contents

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 from 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.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. 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 in all of the properties, 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.

For example, in 1997, we consummated a large acquisition that proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were below the results we had originally projected. The poor production performance of these properties resulted in material downward reserve revisions. There is no assurance that our recent and/or future acquisition activity will not result in similarly disappointing results.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

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 management personnel, none of which is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

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

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. 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 as reserves are produced. Future oil and natural gas production, therefore, is 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 or acquire and develop additional reserves at an acceptable cost.

Drilling is a high-risk activity

The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce

Table of Contents

enough oil and natural gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipelines ruptures, and discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires;
- natural disasters;
- blowouts, surface craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

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. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. 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. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition 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 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 development 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. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. 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.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Our indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources estimated to range from $1.1 billion to $1.3 billion per year over the next three years, depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- breach the numerous financial and other restrictive covenants contained in our existing credit agreements;
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness we still may be able to incur substantially more debt. This could further increase the risks described above.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We exist in a litigious environment

Any constituent could bring suit or allege a violation of an existing contract. This action could delay when operations can actually commence or could cause a halt to production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, planned operations could be delayed which would impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Our financial statements are complex

Due to accounting rules and the nature of our business, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

Since 1998, we have exchanged 31.9 million shares of common stock for debt and convertible securities. 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. Also in 2004 and 2005, we sold 33.8 million shares of common stock to finance acquisitions. In 2006, we issued 6.5 million shares as part of the Stroud acquisition. In 2007, we sold 8.1 million shares of common stock to finance acquisitions. While the exchanges have reduced interest expense, preferred dividends and future repayment obligations, the larger number of common shares outstanding had a dilutive effect on our existing stockholders. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. These limitations may, in certain circumstances, limit or prevent the payment of dividends independent of our dividend policy.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid

The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2005 to December 31, 2007, the price of our common stock reported by the New York Stock Exchange ranged from a low of $12.34 per share to a high of $51.88 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil and natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future, and our stock price could decline as a result.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the date of this filing, we have no unresolved comments from the staff of the Securities and Exchange Commission.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2007. All Gulf of Mexico operations have been reclassified to discontinued operations.

	Average Daily Production (mcfe	Total Production	Percentage of Total	Total Proved Reserves	Percentage of Total Proved

Area	per day)	(mcfe)	Production	(Mmcfe)	Reserves
Southwest	194,060	70,832,032	61%	1,048,314	47%
Appalachia	118,383	43,209,899	37%	1,150,143	52%
Gulf Coast	6,573	2,399,084	2%	34,305	1%
	319,016	116,441,015	100%	2,232,762	100%

We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments; therefore, segment reporting is not applicable to us. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Southwest Area

The Southwest Area conducts drilling, production and field operations in the Barnett Shale of North Central Texas, the Permian Basin of West Texas and eastern New Mexico and the East Texas Basin as well as in the Texas Panhandle and the Anadarko Basin of western Oklahoma. In the Southwest Area, we own 2,928 net producing wells, 96% of which we operate. Our average working interest is 77%. We have approximately 802,000 gross (536,000 net) acres under lease.

Total proved reserves increased 273.4 Bcfe, or 35%, at December 31, 2007 when compared to year-end 2006. Production was more than offset by property purchases (30.2 Bcfe), drilling additions (293.5 Bcfe) and a favorable reserve revision. Annual production increased 28% over 2006. During 2007, the region spent $506.0 million to drill 290.0 (256.4 net) development wells, of which 282.0 (249.5 net) were productive and 6.0 (3.3 net) exploratory wells, of which 4.0 (2.8 net) were productive. During the year, the region achieved a 97% drilling success rate.

At December 31, 2007, the Southwest Area had a development inventory of 397 proven drilling locations and 367 proven recompletions. During the year, the Southwest Area drilled 76 proven locations and added new locations of 188. Development projects include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. These activities also include increasing reserves and production through cost control, upgrading lifting equipment, improving gathering systems and surface facilities and performing restimulations and refracturing operations.

Appalachia Area

Our properties in this area are located in the Appalachian Basin in the northeastern United States principally in Ohio, Pennsylvania, New York, West Virginia and Virginia. The reserves principally produce from the Pennsylvanian (coalbed formation), Upper Devonian, Medina, Clinton, Queenston, Big Lime, Marcellus Shale, Niagaran Reef, Knox, Huntersville Chert, Oriskany and Trenton Black River formations at depths ranging from 2,500 to 12,500 feet. Generally, after initial flush production, most of these properties are characterized by gradual decline rates, typically producing for 10 to 35 years. We own 10,800 net producing wells, 59% of which we operate and 5,100 miles of gas gathering lines. Our average working interest is 71%. We have approximately 2.5 million gross (2.1 million net) acres under lease which includes 407,800 acres where we also own a royalty interest.

Reserves at December 31, 2007 increased 235.1 Bcfe, or 26%, from 2006 due to drilling additions (177.4 Bcfe) and property purchases (102.8 Bcfe) which were partially offset by production. Annual production increased 15% over 2006. During 2007, the region spent $278.1 million to drill 654.0 (427.7 net) development wells, of which 653.0 (426.7 net) were productive and 9 (5.5 net) exploratory wells, of which 7.0 (3.5 net) were productive. During the year, the region achieved approximately a 99% drilling success rate. At December 31, 2007, the Appalachia Area had an inventory of 3,600 proven drilling locations and 394 proven recompletions. During the year, the Appalachia Area drilled 321 proven locations and added 755 new locations.

Gulf Coast Area

The Gulf Coast properties are located onshore in Texas, Louisiana and Mississippi. Our major fields produce from Yegua formations at depths of 12,000 to 14,000 feet in the Upper Texas Gulf Coast, the Upper Oligocene in South Louisiana at depths of 10,000 to 12,000 feet and the Sligo and Hosston formations at depths of 15,000 to 16,500 feet in the Oakvale field in Mississippi. We have approximately 126,000 gross (83,000 net) acres under lease. We own 43 net producing wells in this Area, 98% of which we operate. Our average working interest is 57%.

In the first quarter of 2007, we sold all of our offshore properties. Reserves decreased 33.9 Bcfe, or 50%, from 2006 with property sales (37.1 Bcfe), production and an unfavorable reserve revision partially offset by drilling additions (13.3 Bcfe). On an annual basis, production decreased 17% from 2006. During 2007, the region spent $34.8 million to drill 7.0 (4.3 net) development wells, of which all were productive and 1.0 (1.0 net) exploratory well that was not productive. During the year, the Area had a 81% drilling success rate. At December 31, 2007, the Gulf Coast Area had an inventory of 4 proven drilling locations and 16 proven recompletions.

Table of Contents

Proved Reserves

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

	December 31, 2007	2006	2005	2004	2003
Natural gas (Mmcf)					
Developed	1,144,709	875,395	724,876	580,006	344,187
Undeveloped	688,088	560,583	400,534	366,422	142,217
Total	1,832,797	1,435,978	1,125,410	946,428	486,404
Oil and NGLs (Mbbls)					
Developed	47,015	37,750	33,029	27,715	24,912
Undeveloped	19,645	15,957	13,863	10,451	8,111
Total	66,660	53,707	46,892	38,166	33,023
Total (Mmcfe) [a]	2,232,762	1,758,226	1,406,762	1,175,425	684,541
% Developed	64%	63%	66%	64%	72%

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcfe.

Our percentage of proved developed reserves declined from 2003 to 2004 due to the proved undeveloped reserves acquired in our Great Lakes and Pine Mountain acquisitions which added to our future drilling inventory. From 2004 to 2005, our proved developed percentage increased from 64% to 66% as we continued to drill aggressively. The Stroud acquisition in June of 2006 was primarily responsible for the decrease in the proved developed reserve percentage in 2006. The Stroud acquisition significantly increased our Barnett Shale drilling and prospect inventory. In 2007, the percentage of proved developed reserves increased 1% to 64%.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2007:

	PV-10 [a]		Reserve Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 2,942,845	57%	51,816	737,419	1,048,314	47%
Appalachia	2,128,982	41%	13,742	1,067,691	1,150,143	52%
Gulf Coast	132,997	2%	1,102	27,687	34,305	1%
Total	$ 5,204,824	100%	66,660	1,832,797	2,232,762	100%

(a) PV-10 was prepared using prices in effect at the end of 2007, discounted at 10% per annum. Year-end PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. While the standardized is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $1.5 billion at December 31, 2007.

At year-end 2006, the following independent petroleum consultants reviewed our 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 historical experience in engineering certain properties. At December 31, 2007, these consultants collectively reviewed approximately 86% of our proved reserves. All estimates of oil and gas reserves are subject to uncertainty. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. We did not file any reports during the year ended December 31, 2007 with any federal authority or agency with respect to our estimates of oil and natural gas reserves.

Table of Contents

The following table sets forth the estimated future net revenues, excluding open hedging contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices and average field prices used in projecting them over the past five years (in millions except prices):

	December 31,				
	2007	2006	2005	2004	2003
Future net revenue	$11,908	$6,391	$10,429	$5,035	$2,687
Present value					
Before income tax	5,205	2,771	4,887	2,396	1,396
After income tax (Standardized Measure)	3,666	2,002	3,384	1,749	1,003
Benchmark prices					
Oil price (per barrel)	$ 95.98	$61.05	$ 61.04	$43.33	$32.52
Gas price (per mcf)	$ 6.80	$ 5.64	$ 10.08	$ 6.18	$ 6.19
Wellhead prices					
Oil price (per barrel)	$ 91.88	$57.66	$ 57.80	$40.44	$29.48
Gas price (per mcf)	$ 6.44	$ 5.24	$ 9.83	$ 6.05	$ 6.03

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations, prepared in accordance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities, are based on costs and prices in effect at December 31 of each year, without escalation. 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.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2007. We also own royalty interests in an additional 1,649 wells where we do not own a working interest. If we own both a royalty and a working interest in a well such interests are included in the table below. Wells are classified as crude oil or natural gas according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working
	Gross	Net	Interest
Natural gas	16,253	11,341	70%
Crude oil	2,832	2,474	87%
Total	19,085	13,815	72%

The day-to-day operations of oil and gas properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Acreage

We own interests in developed and undeveloped oil and gas acreage. These ownership interests generally take the form of working interests in oil and gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves.

Table of Contents

The following table sets forth certain information regarding our developed and undeveloped acreage in which we own a working interest as of December 31, 2007. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alabama			65,617	54,451	65,617	54,451
Louisiana	3,289	2,058	17,454	8,457	20,743	10,515
Michigan	162	162	855	378	1,017	540
Mississippi	3,954	2,167	25,214	7,956	29,168	10,123
New York	187,124	177,871	146,302	128,361	333,426	306,232
Ohio	270,638	254,257	239,569	217,959	510,207	472,216
Oklahoma	160,588	100,855	147,523	79,200	308,111	180,055
Pennsylvania	427,516	388,947	632,448	532,328	1,059,964	921,275
Texas	179,500	146,680	324,180	236,906	503,680	383,586
Virginia	152,300	50,330	166,134	74,393	318,434	124,723
West Virginia	48,468	47,883	107,300	104,300	155,768	152,183
	1,433,539	1,171,210	1,872,596	1,444,689	3,306,135	2,615,899
Average working interest		82%		77%		79%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2008	157,342	123,432	8%
2009	244,817	173,246	11%
2010	299,460	219,017	14%
2011	162,742	136,695	9%
2012	303,922	250,387	16%

Drilling Results

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. As of December 31, 2007, we were in the process of drilling 131 gross (83 net) wells.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	942.0	680.5	992.0	689.7	813.0	573.8
Dry	9.0	7.9	8.0	4.6	10.0	7.7
Exploratory wells						
Productive	11.0	6.3	12.0	6.9	13.0	8.1
Dry	5.0	3.5	5.0	2.6	5.0	3.9
Total wells						
Productive	953.0	686.8	1,004.0	696.6	826.0	581.9
Dry	14.0	11.4	13.0	7.2	15.0	11.6

Total	967.0	698.2	1,017.0	703.8	841.0	593.5
Success ratio	99%	98%	99%	99%	98%	98%

Table of Contents

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- burdens such as net profit interests.

ITEM 3. LEGAL PROCEEDINGS

We have been named as a defendant in a number of legal actions arising in the ordinary course of business. In the opinion of management, such litigation and claims are likely to be resolved without a material adverse effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year. See also Note 14 to our consolidated financial statements.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2007.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol RRC. During 2007, trading volume averaged 1.6 million shares per day. On December 20, 2007, we were selected to be included in the S&P 500 index. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2006			
First quarter	$30.52	$22.52	$ 0.02
Second quarter	30.29	21.74	0.02
Third quarter	30.37	23.38	0.02
Fourth quarter	31.77	22.80	0.03
2007			
First quarter	$33.80	$25.59	$ 0.03
Second quarter	40.50	33.40	0.03
Third quarter	41.87	33.28	0.03
Fourth quarter	51.88	37.17	0.04

Between January 1, 2008 and February 20, 2008, the common stock traded at prices between $43.02 and $64.50 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 20, 2008, there were approximately 1,848 holders of record of our common stock.

19

Table of Contents

Dividends

In December 2007, the Board of Directors increased our quarterly dividend to $0.04 per common share. The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The bank credit facility and our senior subordinated notes allow for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board and will depend upon our level of earnings and capital expenditures and other matters that the Board of Directors deems relevant. For more information see information set forth in Item 7 of this report Management s Discussion and Analysis of Financial Condition and Results of Operations.

Issuer Purchases of Equity Securities

We have a repurchase program approved by the Board of Directors in 2006 for the repurchase of up to $10.0 million of common stock based on market conditions and opportunities. There were no repurchases during the fourth quarter of 2007. As of December 31, 2007, we have $4.7 million remaining under this authorization.

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC s executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of the common stock, the Dow Jones U.S. Exploration and Production Index and the S&P 500 Index for the five years ended December 31, 2007. The graph assumes that $100 was invested in the Company s common stock and each index on December 31, 2002.

Comparison of Five Year Cumulative Returns

	2002	2003	2004	2005	2006	2007
Range Resources Corporation	$100	$175	$379	$732	$762	$1,427
DJ U.S. Expl. & Prod. Index	100	129	182	298	312	445
S&P 500	100	126	138	141	161	167

* The performance graph and the information contained in this section is not soliciting material, is being furnished not filed with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and

irrespective of any general incorporation language contained in such filing.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2007. Significant producing property acquisitions in 2006 and 2004 affect the comparability of year-to-year financial and operating data. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. Accordingly, the financial and statistical data contained in the following discussion reflects the reclassification of our Gulf of Mexico operations to discontinued operations. All weighted average shares and per share data have been adjusted for the three-for-two stock split effected December 2, 2005. This information should be read in conjunction with Item 7 of this report Management s Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements and related notes included elsewhere in this report.

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in thousands, except per share data)				
Balance Sheet Data:					
Current assets [(a)]	$ 261,814	$ 388,925	$ 207,977	$ 136,336	$ 66,092
Current liabilities [(b)]	305,433	251,685	321,760	177,162	106,964
Oil and gas properties, net	3,503,808	2,608,088	1,679,593	1,340,077	658,798
Total assets	4,016,508	3,187,674	2,018,985	1,595,406	830,091
Bank debt	303,500	452,000	269,200	423,900	178,200
Subordinated notes	847,158	596,782	346,948	196,656	109,980
Stockholders equity[(c)]	1,728,022	1,256,161	696,923	566,340	274,066
Weighted average dilutive shares outstanding	149,911	138,711	129,125	97,998	86,775
Cash dividends declared per common share	0.13	0.09	.0599	.0267	.0067
Cash Flow Data:					
Net cash provided from operating activities	$ 642,291	$ 479,875	$ 325,745	$ 209,249	$124,680
Net cash used in investing activities	1,020,572	911,659	432,377	624,301	186,838
Net cash provided from financing activities	379,917	429,416	93,000	432,803	61,455

(a) 2007 included deferred tax assets of $26.9 million. 2005 included deferred tax assets of $61.7 million compared to $26.3 million in 2004 and $19.9 million in 2003. 2007 includes a $53.0 million unrealized derivative asset compared to $93.6 million in 2006.

(b) 2007 includes unrealized derivative liabilities of $30.5 million compared to $4.6 million in 2006, $160.1 million in 2005, $61.0 million in 2004 and $54.3 million in 2003.

(c) Stockholders equity includes other comprehensive income (loss) of ($26.8 million) in 2007 compared to $36.5 million in 2006, ($147.1 million) in 2005, ($43.3 million) in 2004 and ($42.9 million) in 2003.

Table of Contents

Statement of Operations Data:

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in thousands, except per share data)				
Revenues					
Oil and gas sales	$862,537	$599,139	$495,470	$278,903	$179,074
Transportation and gathering	2,290	2,422	2,306	2,002	3,248
Gain (loss) on retirement of securities				(39)	18,526
Derivative fair value (loss) income	(7,767)	142,395	10,303	614	(1,282)
Other	5,031	856	1,024	1,588	(865)
Total revenue	862,091	744,812	509,103	283,068	198,701
Costs and expenses					
Direct operating	108,741	81,261	57,866	39,419	28,110
Production and ad valorem taxes	42,443	36,415	30,822	19,845	12,059
Exploration	43,345	44,088	29,529	12,619	12,530
General and administrative	68,428	49,886	33,444	20,634	17,818
Deferred compensation plan	28,332	6,873	29,474	19,176	6,559
Interest expense and dividends on trust preferred	77,737	55,849	37,619	22,437	21,507
Depletion, depreciation and amortization	227,328	154,739	114,364	80,628	62,687
Total costs and expenses	596,354	429,111	333,118	214,758	161,270
Income from continuing operations before income taxes and accounting change	265,737	315,701	175,985	68,310	37,431
Income tax provision (benefit)					
Current	320	1,912	1,071	(245)	170
Deferred	98,441	119,840	64,809	25,327	14,125
	98,761	121,752	65,880	25,082	14,295
Income from continuing operations	166,976	193,949	110,105	43,228	23,136
Income (loss) from discontinued operations	63,593	(35,247)	906	(997)	7,788
Income before cumulative effect of changes in accounting	230,569	158,702	111,011	42,231	30,924

principles					
Cumulative effect of changes in accounting principles, net of taxes					4,491
Net income	230,569	158,702	111,011	42,231	35,415
Preferred dividends				(5,163)	(803)
Net income available to common stockholders	$230,569	$158,702	$111,011	$ 37,068	$ 34,612
Earnings per common share:					
Basic income from continuing operations	$ 1.16	$ 1.45	$ 0.89	$ 0.41	$ 0.27
income (loss) from discontinued operations	0.44	(0.26)		(0.01)	0.10
cumulative effect of changes in accounting principles					0.05
net income	$ 1.60	$ 1.19	$ 0.89	$ 0.40	$ 0.42
Diluted income from continuing operations	$ 1.11	$ 1.39	$ 0.85	$ 0.39	$ 0.27
income (loss) from discontinued operations	0.43	(0.25)	0.01	(0.01)	0.09
cumulative effect of changes in accounting principles					0.05
net income	$ 1.54	$ 1.14	$ 0.86	$ 0.38	$ 0.41

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with Item 6, Selected Financial Data and our consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Disclosures Regarding Forward-Looking Statements at the beginning of this Annual Report and Risk Factors in Item 1A for additional discussion of some of these factors and risks.

Items Impacting the Comparability to Prior Year Reports

In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. Accordingly, the financial and statistical data contained in the following discussion for all periods presented reflects the reclassification of our Gulf of Mexico operations to discontinued operations.

Overview of Our Business

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We operate in one segment. We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our strategy is to increase reserves and production through internally generated drilling projects coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. We use the successful efforts method of accounting for our oil and gas activities. Our corporate headquarters are in Fort Worth, Texas.

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. As a mature region, while new discoveries of oil and gas occur in the United States, the size and frequency of these discoveries is generally declining, while finding and development costs are increasing. We believe that there remain areas of the United States, such as the Appalachian Basin and certain areas in our Southwest and Gulf Coast Areas, which are underexplored or have not been fully explored and developed with the benefit of newly available exploration, production and reserve enhancement technology. Examples of such technology include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, horizontal drilling and completion techniques, secondary and tertiary recovery practices, and automated remote well monitoring and control devices.

Another characteristic of a mature region is the historical exit of larger independent producers and major oil companies from such regions. These companies, searching for ever larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided acquisition opportunities for companies like ours that maintain well-equipped technical teams capable of generating additional value from these assets. In other situations, to increase cash flow without increasing capital spending, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures and farm-in arrangements.

We believe the acquisition market for oil and gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities. Acquisition values have reached historic highs and we expect these values to remain high in 2008. In addition, we expect drilling and service costs to remain at a high level in 2008 and for lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Oil and gas is a commodity. The price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically over the last ten years. Demand is impacted by general economic conditions, estimates of gas in storage, weather and other seasonal condition, including hurricanes and tropical storms. Market conditions involving over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. A factor impacting the future supply balance is the recent increase in the United States LNG import capacity. Significant LNG capacity

Table of Contents

increases have been announced which may result in increased price volatility. A substantial or extended decline in oil and gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and our ability to access capital markets.

Source of Our Revenues

We derive our revenues from the sale of oil and gas that is produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, quality, BTU content and transportation costs to market. The price of oil and natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our natural gas and oil production. During 2006 and 2005 the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods. Our realized price calculations include the effects of the settlement of derivative contracts that are accounted for as hedges and the settlement of derivative contracts that are not accounted for as hedges.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include workovers and repairs to our oil and gas properties. These costs are expected to remain high in 2008 as the demand for these services continues to increase. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

Production and Ad Valorem Taxes. These costs are taxes paid on produced oil and gas based on a percentage of market prices (not at hedged prices) or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. Geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory or dry holes. Exploration expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

General and Administrative Expense. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

Interest. We typically finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facility and with our longer term debt securities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We will likely continue to incur significant interest expense as we continue to grow. We expect our 2008 capital budget to be funded primarily with internal cash flow and asset sales.

Depreciation, Depletion and Amortization. The systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities. This category also includes unproved property impairment and costs associated with lease expirations.

Income Taxes. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs (IDC). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. Currently, substantially all of our federal taxes are deferred; however, at some point, we anticipate using all of our net operating loss carryforwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

Table of Contents

Management s Discussion and Analysis of Income and Operations

Overview of 2007 Results

During 2007, we achieved the following results:

- Achieved 22% production growth and 27% reserve growth;
- Drilled 698 net wells;
- Continued expansion of drilling inventory and emerging plays;
- Posted record financial results and continued balance sheet improvements; and
- Completed acquisitions of properties containing 133 Bcfe of proved reserves.

Our 2007 performance reflects another year of successfully executing our strategy of growth through drilling and complementary acquisitions. The business of exploring for, developing, and acquiring oil and gas is highly competitive and capital intensive. As in any commodity business, the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for stockholders. Generating meaningful growth while containing costs presents an ongoing challenge. During periods of historically high oil and gas prices, drilling service and operating cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2007 including attracting and retaining qualified personnel, consummating and integrating acquisitions, and accessing the capital markets to fund our growth on sufficiently favorable terms. We have continued to expand and improve the technical staff through the hiring of additional experienced professionals. Our inventory of exploration and development prospects continues to be strong, providing new growth opportunities, greater diversification of technical risk and better efficiency.

Total revenues increased 16% in 2007 over the same period of 2006. This increase is due to higher production and higher realized oil and gas prices. Our 2007 production growth is due to the continued success of our drilling program and to acquisitions completed in 2006 and 2007. Realized prices were higher by 18% in 2007. As discussed in Item 1A of this report, significant changes in oil and gas prices can have a significant impact on our balance sheet and our results of operations, including the fair value of our derivatives.

Oil and Gas Sales, Production and Realized Price Calculations

Our oil and gas sales vary from year to year as a result of changes in commodity prices or volumes of production sold. Hedges realized reflect settlements on those derivatives that qualify for hedge accounting. Oil and gas sales increased 44% from 2006 due to a 22% increase in production and an 18% increase in realized prices. Oil and gas sales in 2006 increased 21% from 2005 due to an 18% increase in production and a 3% increase in realized prices. The following table illustrates the primary components of oil and gas sales for each of the last three years (in thousands):

	2007	2006	2005
Oil and Gas Sales			
Oil wellhead	$ 226,686	$ 189,516	$ 156,102
Oil hedges realized	(23,755)	(45,265)	(42,948)
Total oil revenue	$ 202,931	$ 144,251	$ 113,154
Gas wellhead	$ 585,538	$ 466,099	$ 461,132
Gas hedges realized	27,916	(47,916)	(106,404)
Total gas revenue	$ 613,454	$ 418,183	$ 354,728
NGL	$ 46,152	$ 36,705	$ 31,891

NGL hedges realized			(4,302)
Total NGL revenue	$ 46,152	$ 36,705	$ 27,589
Combined wellhead	$ 858,376	$ 692,320	$ 649,126
Combined hedges	4,161	(93,181)	(153,655)
Total oil and gas sales	$ 862,537	$ 599,139	$ 495,471

Table of Contents

Our production continues to grow through continued drilling success and additions from acquisitions. For 2007, our production volumes increased 15% in our Appalachia Area, increased 28% in our Southwest Area and declined 17% in our Gulf Coast Area. For 2006, our production volumes increased 10% in our Appalachia Area, increased 29% in our Southwest Area and declined 36% in our Gulf Coast Area. Our production for each of the last three years is set forth in the following table:

	2007	2006	2005
Production			
Crude oil (bbls)	3,359,668	3,039,150	2,929,013
NGLs (bbls)	1,114,730	1,091,785	1,011,692
Natural gas (mcf)	89,594,626	70,712,770	57,608,816
Total (mcfe) [(a)]	116,441,014	95,498,380	81,253,046
Average daily production			
Crude oil (bbls)	9,205	8,326	8,025
NGLs (bbls)	3,054	2,991	2,772
Natural gas (mcf)	245,465	193,734	157,832
Total (mcfe) [(a)]	319,016	261,639	222,611

[(a)] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcfe.

Our average realized price (including all derivative settlements) received for oil and gas during 2007 was $8.02 per mcfe compared to $6.80 per mcfe in 2006 and $6.13 per mcfe in 2005. Our average realized price calculation (including all derivative settlements) includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average price calculations for each of the last three years is shown below:

	2007	2006	2005
Average Prices			
Average sales prices (wellhead):			
Crude oil (per bbl)	$67.47	$62.36	$53.30
NGLs (per bbl)	$41.40	$33.62	$31.52
Natural gas (per mcf)	$ 6.54	$ 6.59	$ 8.00
Total (per mcfe) [(a)]	$ 7.37	$ 7.25	$ 7.99
Average realized prices (including derivatives that qualify for hedge accounting):			
Crude oil (per bbl)	$60.40	$47.46	$38.63
NGLs (per bbl)	$41.40	$33.62	$27.27
Natural gas (per mcf)	$ 6.85	$ 5.91	$ 6.16
Total (per mcfe) [(a)]	$ 7.41	$ 6.27	$ 6.10
Average realized prices (including all derivative settlements):			
Crude oil (per bbl)	$60.16	$47.46	$38.63
NGLs (per bbl)	$41.40	$33.62	$27.27
Natural gas (per mcf)	$ 7.66	$ 6.62	$ 6.21

Total (per mcfe) [a]	$ 8.02	$ 6.80	$ 6.13
Average NYMEX prices [b]:			
Oil (per bbl)	$72.34	$66.22	$56.56
Natural gas (per mcf)	$ 6.92	$ 7.26	$ 8.55

[a] Oil and NGLs are converted at the rate of one barrel equals six mcfe.

[b] Based on average of bid week prompt month prices.

Table of Contents

Derivative fair value income (loss) decreased to a loss of $7.8 million in 2007 compared to a gain of $142.4 million in 2006 and a gain of $10.3 million in 2005. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, the portion of our derivatives which were designated to our Gulf of Mexico production was marked to market resulting in fair value income of $209,000. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian Basin production to market due to the anticipated sale of a portion of our Permian properties resulting in derivative fair value loss of $14.7 million. The loss of hedge accounting treatment creates volatility in our revenues as gains and losses from non-hedge derivatives are included in total revenues and are not included in our balance sheet in accumulated other compensation loss. As commodity prices increase or decrease such changes will have an opposite effect on the mark-to-market value of our derivatives. Because oil prices increased dramatically in 2007, our derivatives became comparatively less valuable. However, we expect these losses will be offset by higher wellhead revenues in the future. Beginning in the third quarter of 2007, we have also entered into basis swap agreements which do not qualify for hedge accounting purposes and are marked to market. Hedge ineffectiveness included in this category is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133. The following table presents information about the components of derivative fair value income (loss) for each of the years in the three-year period ended December 31, 2007 (in thousands):

	2007	2006	2005
Hedge ineffectiveness realized	$ 968	$	$
unrealized [a]	(820)	5,965	(3,471)
Change in fair value of derivatives that do not qualify for hedge accounting [a]	(78,769)	86,491	10,868
Realized gain on settlements gas [b]	71,098	49,939	2,906
Realized loss on settlements oil [b]	(244)		
Derivative fair value (loss) income	$ (7,767)	$ 142,395	$ 10,303

(a) These amounts are unrealized and are not included in average sales price calculations.

(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting which before settlement have been recognized in the unrealized mark-to-market component of derivative fair value income (loss). These settlements are included in average realized price calculations (including all derivative settlements).

Other revenue increased in 2007 to a gain of $5.0 million compared to a gain of $856,000 in 2006 and a gain of $1.0 million in 2005. The 2007 period includes income from equity method investments of $974,000 and other miscellaneous income. The 2006 period includes income from equity method investments of $548,000. The 2005 period includes income of $514,000 from Independent Producer Finance, one of our businesses that no longer operates.

Comparison of 2007 and 2006 Expenses

Our unit costs have increased as we continue to grow. We believe some of our expense fluctuations should be analyzed on a unit-of-production, or per mcfe basis. The following table presents information about certain of our expenses on a per mcfe basis for 2007 and 2006:

Operating expenses (per mcfe)	2007	2006	Change	% Change
Direct operating expense	$0.93	$0.85	$ 0.08	9%
Production and ad valorem tax expense	0.36	0.38	(0.02)	5%
General and administrative expense	0.59	0.52	0.07	13%
Interest expense	0.67	0.58	0.09	15%
Depletion, depreciation and amortization expense	1.95	1.62	0.33	20%

Direct operating expense for 2007 increased $27.5 million, or 33.8%, to $108.7 million due to higher oilfield service costs, higher volumes and the integration of our recent acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. On a per mcfe basis, direct operating expenses were $0.93 and increased $0.08 from 2006 with the increase consisting primarily of higher water disposal costs ($0.02 per mcfe), higher well services and equipment costs ($0.04 per mcfe), higher workover costs ($0.02 per mcfe) and a $0.01 per mcfe increase in stock- based compensation. The following table summarizes direct operating expenses per mcfe for 2007 and 2006:

	2007	2006	Change	% Change
Lease operating expense	$ 0.85	$ 0.80	$ 0.05	6%
Workovers	0.06	0.04	0.02	50%
Stock-based compensation	0.02	0.01	0.01	100%
Total direct operating expenses	$ 0.93	$ 0.85	$ 0.08	9%

Production and ad valorem taxes are paid based on market prices and not hedged prices. For 2007, these taxes increased $6.0 million, or 17%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes decreased from $0.38 in 2006 to $0.36 in 2007 with lower ad valorem taxes per mcfe due to lower property tax rates in Texas as a result of the new margin tax.

General and administrative expense for 2007 increased $18.5 million, or 37%, primarily due to higher salaries and benefits of $9.2 million ($0.03 per mcfe), higher office rent and general office expense of $2.3 million ($0.01 per mcfe) and higher stock based compensation of $4.0 million ($0.01 per mcfe). The stock-based compensation expense represents amortization of restricted stock grants and stock option/SARs expense under SFAS No. 123(R). On a per mcfe basis, general and administration expense increased from $0.52 in 2006 to $0.59 in 2007. The following table summarizes general and administrative expenses per mcfe for 2007 and 2006:

	2007	2006	Change	% Change
General and administrative	$ 0.43	$ 0.37	$ 0.06	16%
Stock-based compensation	0.16	0.15	0.01	7%
Total general and administrative expenses	$ 0.59	$ 0.52	$ 0.07	13%

Interest expense for 2007 increased $21.9 million, or 39%, to $77.7 million with higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In September 2007, we issued $250.0 million of 7.5% senior subordinated notes due 2017 which added $4.8 million of interest costs in 2007. In May 2006, we issued $250.0 million of 7.5% senior subordinated notes due 2016 which increased interest expense by $9.1 million in 2007. The proceeds from these issuances were used to retire shorter term lower rate bank debt. In 2007, the average debt outstanding on the bank credit facility was $417.6 million with an average interest rate of 6.4% compared to an average debt outstanding in 2006 of $347.8 million, with an average interest rates of 6.4%.

Depletion, depreciation and amortization (DD&A) for 2007 increased $72.6 million, or 47%, to $227.3 million, due to higher production and higher depletion rates. Depletion rates increased 16%, or $0.24 per mcfe, due to increased drilling costs and the mix of our production. DD&A increased from $1.62 per mcfe in 2006 to $1.95 per mcfe in 2007. For 2008, based on our current reserve base, we expect our DD&A rate to average approximately $2.10 per mcfe. The twelve months ended 2007 also includes higher unproved property impairment of $3.0 million ($0.03 per mcfe), higher acreage expiration expense of $3.4 million ($0.03 per mcfe), higher accretion expense related to asset retirement obligations of $2.3 million ($0.01 per mcfe) and higher depreciation expense of $3.3 million ($0.01 per mcfe). In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million.

Our operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense and deferred compensation plan expense. In 2007, stock-based compensation of $24.0 million is a component of direct operating expense ($1.8 million), exploration expense ($3.5 million) and general and administrative expense ($18.2 million). In 2006, stock-based compensation of $19.1 million is a component of direct operating expense ($1.4 million), exploration expense ($3.1 million) and general and administrative expense ($14.3 million). In 2007 and 2006, this expense represents the amortization of restricted stock grants, stock options and SARs as they become vested.

Exploration expense for 2007 decreased $743,000, or 2%, to $43.3 million due to lower seismic costs ($4.3 million) somewhat offset by higher personnel costs. The following table details our exploration-related expenses (in thousands):

	2007	2006	Change	% Change
Dry hole expense	$ 15,149	$ 15,084	$ 65	
Seismic	10,933	15,277	(4,344)	28%
Personnel expense	8,924	6,917	2,007	29%
Stock-based compensation expense	3,473	3,079	394	13%
Delay rentals and other	4,866	3,731	1,135	30%
Total exploration expense	$ 43,345	$ 44,088	$ (743)	2%

Deferred compensation plan expense for 2007 increased to $28.3 million, or 312%, from $6.9 million in 2006. This non-cash expense relates to the increase or decrease in value of our common stock and other investments held in our deferred compensation plans. In the fourth quarter of 2007, we recorded adjustments that decreased deferred compensation plan expense by $12.4 million. Such adjustments were the result of an incorrect practice of adjusting our deferred compensation liability for market value changes in unvested shares held in our deferred compensation plan. In addition, interest and dividends related to the marketable securities held in the deferred compensation plan were inappropriately recorded in accumulated other comprehensive loss. Of the $12.4 million decrease in deferred compensation expense, $7.1 million is related to periods prior to 2007 and $5.3 million is related to the first three quarters of 2007. Our common stock price increased from $26.34 per share at the end of 2005 to $27.46 per share at the end of 2006 to $51.36 per share at the end of 2007.

Income tax expense for 2007 decreased $23.0 million, or 19%, to $98.8 million due to a 16% decrease in income from continuing operations. Our effective tax rate was 37% for 2007 compared to 39% for 2006. The twelve months ended December 31, 2007 includes a non-recurring $3.0 million tax benefit related to an increase in the Texas Margin Tax credit carryover. This benefit is related to a change in the Texas law allowing companies to realize tax attributes carrying forward from the previously applicable Texas Franchise tax to the new Texas Margin tax. The twelve months ended December 31, 2006 includes a $2.8 million tax expense for changes in state tax rates. We expect our effective tax rate to be approximately 37% for 2008. Given our available net operating loss carryover, we do not expect to pay significant federal income taxes. We received a refund of $299,000 for state income taxes in 2007.

Discontinued operations includes the operating results related to our Gulf of Mexico properties and Austin Chalk properties that we sold in the first quarter of 2007. See also Note 4 to our consolidated financial statements.

Comparison of 2006 to 2005 Expenses

Our unit costs have increased as we continue to grow. We believe some of our expense fluctuations should be analyzed on a unit of production, or per mcfe basis. The following table presents information about certain of our operating expenses on a per mcfe basis for 2006 and 2005:

Operating expenses (per mcfe)	2006	2005	Change	% Change
Direct operating expense	$0.85	$0.71	$0.14	20%
Production and ad valorem tax expense	0.38	0.38		
General and administration expense	0.52	0.41	0.11	27%
Interest expense	0.58	0.46	0.12	26%
Depletion, depreciation and amortization expense	1.62	1.41	0.21	15%

Direct operating expense for 2006 increased $23.4 million to $81.3 million due to higher oilfield service costs, higher volumes and the integration of our recent acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. On a per mcfe basis, direct operating expenses were $0.85

and increased 20% or $0.14 from 2005 consisting of higher utilities ($0.01 per mcfe), higher water disposal and equipment costs ($0.06 per mcfe) and higher pumper expenses ($0.01 per mcfe). The following table summarizes direct operating expenses per mcfe for 2006 and 2005:

Table of Contents