RANGE RESOURCES CORP
Form 10-K
February 27, 2007

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, 2006

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.)
777 Main Street, Suite 800, 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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerate filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

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 30, 2006 was $3,681,364,000.

As of February 20, 2007, there were 139,210,404 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 2007 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 subsidiaries. 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 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, 2006

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 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 seek to increase reserves and production through internally generated drilling projects, coupled with complementary acquisitions.

At year-end 2006, our proved reserves had the following characteristics:

- 1.8 Tcfe of proved reserves;
- 82% natural gas;
- 63% proved developed;
- 80% operated;
- a reserve life of 16.3 years (based on fourth quarter 2006 production); and
- a pre-tax present value of $2.8 billion ($2.0 billion after tax).

At year-end 2006, we owned 3,215,000 gross (2,500,000 net) acres of leasehold, which includes over 70,000 of acres associated with royalties. We have built a multi-year inventory of drilling projects which is estimated to be over 9,400 identified drilling locations.

Range was 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 243%, while production has increased 81% during that same period.

Our corporate offices are located at 777 Main Street, Suite 800, Fort Worth, Texas 76102. Our telephone number is (817) 870-2601. Effective May 1st, 2007, our corporate offices will be located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102.

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 to achieve such growth. Our strategy requires us to make significant investments in technical staff, acreage and seismic data and technology to build drilling inventory. In implementing our strategy, we employ 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 Gulf Coast. 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 combine 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 9,400 identified drilling locations in inventory. In 2006, we drilled 1,017 gross (704 net) wells. In 2007, our capital program targets the drilling of 924 gross (691 net) wells.

Make Complementary Acquisitions. We target complementary acquisitions in existing core areas and focus on acquisition candidates 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 $1.3 billion of complementary acquisitions. These acquisitions have been located in the Southwestern and Appalachian regions.

Manage Our Risk Exposure. Allocating the majority of our capital spending to long-term development projects in areas where multiple productive horizons exist serves to reduce our risk exposure. Where our exploration projects may involve high dry hole costs, we often bring in industry partners in order to reduce financial exposure. We also invest in new seismic data and technology each year. By equipping our geologists and geophysicists with state-of-the-art seismic technology with multiple reprocessing applications, we hope to multiply the number of higher potential exploration prospects we drill without substantially adding to dry hole risk.

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 in order 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 Range. As of December 31, 2006, our employees owned equity securities (vested and unvested) which had a market value of over $170.0 million.

Significant Accomplishments in 2006

Production and reserve growth The fourth quarter of 2006 marked the 16th consecutive quarter of sequential production growth. In 2006, our annual production averaged 276.1 Mmcfe per day, an increase of 15% from 2005. 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 sixteen quarters will be challenging to sustain, the quality of our technical teams and our sizable drilling inventory bode well for the future. Proven reserves increased 25% in 2006 to 1.8 Tcfe, marking the fifth consecutive year our proven reserves have increased.

Table of Contents

Successful drilling program In 2006, we drilled 1,017 gross wells. Competition for quality drilling and completion well services was intense in 2006, yet we were able to increase our number of wells drilled by 21% over 2005. 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 important. Production was replaced by 377% through drilling in 2006, and our overall success rate was 99%. The increased pace of drilling did not adversely impact the quality of our drilling program as the 99% success ratio in 2006 compares favorably to the 98% success ratio in 2005.

Continued expansion of drilling inventory and emerging plays To continue to grow, the size of our prospect inventory must also increase. Our drilling inventory currently includes over 9,400 projects, up from 7,700 at year-end 2005. Meaningful expansion of our coal bed methane plays and our shale plays occurred in 2006. We have now leased 276,000 net acres in our coal bed methane plays and 567,000 net acres in our shale plays. In addition to the expansion of our emerging plays, we have hired additional quality experienced technical professionals to assist us in this effort.

Record financial results and balance sheet improvement Growth in production volumes and higher oil and gas prices drove our record financial performance in 2006. Revenue, net income, and net cash flow provided from operating activities all reached record highs. The balance sheet continued to improve in 2006 as 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. Future cash flow will be enhanced through lower income tax payments due to a $229.6 million net operating loss carryforward.

Successful acquisition completed In June 2006 we acquired Stroud Energy, Inc. (Stroud) for $171.5 million in cash and 6.5 million shares of our common stock. The transaction was structured as a merger with Stroud shareholders electing to receive either cash, Range stock, or a combination of both cash and stock. Stroud was a private Fort Worth based independent oil and gas company with operations located in the Barnett Shale play in North Texas, the Cotton Valley in East Texas and the Austin Chalk in Central Texas. We estimate the proved reserves attributable to the Stroud properties totaled 171 Bcfe. Over 90% of Stroud s Barnett Shale acreage is located in the core or expanding core portions of the Barnett Shale play. In the first quarter of 2007, we sold the Austin Chalk properties in Central Texas for proceeds of $80.4 million.

Plans for 2007

We have announced a $698.0 million capital budget for 2007, excluding acquisitions. The budget includes $600.0 million to drill 924 gross (691 net) wells and to undertake 72 gross (52 net) recompletions. Approximately 57% of the budget is attributable to the Southwest Division, with 37% allocated to the Appalachia Division and 6% to the Gulf Coast Division. Also included is $58.0 million for land, $20.0 million for seismic and $20.0 million for the expansion and enhancement of gathering systems and facilities. We anticipate drilling slightly fewer shallow wells in favor of deeper wells in 2007 as we seek to improve returns. Deeper wells are typically more costly than shallow wells.

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.

	Year Ended December 31, 2006	2005	2004
Production			
Gas (Mmcf)	75,267	63,004	50,722
Crude oil (Mbbl)	3,160	3,031	2,512
Natural gas liquids (Mbbl)	1,092	1,012	988
Total (Mmcfe) [a]	100,775	87,263	71,726
Revenues ($000)			
Gas	$ 497,854	$ 380,131	$ 225,738
Crude oil	149,370	117,354	70,439
Natural gas liquids	36,704	27,589	19,526
Transportation and gathering	2,507	2,461	2,202
Total	686,435	527,535	317,905
Direct operating expenses [b]	92,224	67,112	46,308
Production and ad valorem taxes	36,915	31,516	20,504
Gross margin	$ 557,296	$ 428,907	$ 251,093
Average sales price (excluding hedging)			
Gas (per mcf)	$ 6.58	$ 7.98	$ 5.79
Crude oil (per bbl)	62.60	53.31	39.25
Natural gas liquids (per bbl)	33.62	31.52	23.73
Total (per mcfe) [a]	7.25	7.98	5.80
Average sales price (including hedging)			
Gas (per mcf)	$ 6.61	$ 6.03	$ 4.45
Crude oil (per bbl)	47.27	38.71	28.04
Natural gas liquids (per bbl)	33.62	27.27	19.76
Total (per mcfe) [a]	6.79	6.02	4.40
Operating costs (per mcfe)			
Direct [b]	$ 0.92	$ 0.77	$ 0.65
Production and ad valorem taxes	0.37	0.36	0.29
Total operating costs	$ 1.29	$ 1.13	$ 0.94
Gross margin (per mcfe)	$ 5.53	$ 4.92	$ 3.50

(a) Oil and NGLs are converted to

mcfe at the rate of one barrel equals six mcfe.

(b) 2006 direct operating expenses include $1.4 million (or $0.01 per mcfe) of non-cash stock-based compensation related to the adoption of SFAS No. 123(R).

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.

Employees

As of January 1, 2007, we had 644 full-time employees, 358 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 utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field and on-site production operation services.

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 777 Main Street, Suite 800, Fort Worth, Texas 76102.

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, N.E., 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.

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. Gas sales are made pursuant to a variety of contractual arrangements; generally month-to-month and one to five-year contracts. Less than 10% 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, gas is sold on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on local indices. Less than 500 mcf per day is sold under long-term fixed price contracts. Many contracts contain provisions for periodic price adjustment, termination and other terms customary in the industry. Gas is sold to utilities, marketing companies and industrial users. Oil is sold 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 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 has 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 Divisions, 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 4,900 miles of gas gathering pipelines which transport a majority 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.

5

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 in order 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.

Certain operations that we conduct are on federal oil and gas leases which are administered by the Minerals Management Service (MMS). These leases contain relatively standardized terms and require compliance with detailed MMS regulations pursuant to the Outer Continental Shelf Lands Act, (OCSLA) (which are subject to change by the MMS). Lessees must obtain a permit from the MMS prior to the commencement of drilling, and comply with regulation governing, among other things, engineering, and construction specifications for production facilities, safety procedures, plugging and abandonment of Outer Continental Shelf, (OCS), wells, the valuation of production, and the removal of facilities. Under certain circumstances, the MMS may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operation. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the MMS exempts the lessee from such obligations. The cost of such bonds or other surety can be substantial and we can provide no assurance that we can continue to obtain bonds or other surety in all cases.

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 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

Environmental Protection Agency (EPA) issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect 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 2006, nor do we anticipate that such expenditures will be material in 2007.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include 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 liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Furthermore, 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. 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. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment pursuant to environmental statutes, common law or both.

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

The Resource Conservation and Recovery Act (RCRA) as amended, generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy. However, these wastes may be regulated by the EPA or state agencies as 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.

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

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

Table of Contents

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.

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.

In the fourth quarter of 2005, due to the trading volatility of NYMEX gas contracts, we experienced larger than usual differentials between actual prices paid at delivery points and NYMEX based gas hedges. Due to this event, certain of our gas hedges no longer qualify for hedge accounting and are marked to market. This may result in more volatility in our income in future periods.

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.

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

If oil and natural gas prices decrease or exploration efforts are unsuccessful, we may be required to take 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 exploration results or mechanical problems with wells where the cost to redrill or repair does not justify the expense which might occur due to hurricanes.

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.

For example, based primarily on the poor performance of certain properties acquired in 1997 and 1998 and significantly lower oil and natural gas prices, we recorded impairments of $215.0 million in 1998 and $29.9 million in 1999. At year-end 2001, we recorded an impairment of $31.1 million due to lower year-end prices. At year-end 2004, we recorded an impairment of $3.6 million on an offshore property due to hurricane damage and related production declines. In the third quarter of 2006, we recorded a $2.4 million impairment on an offshore property due to declining oil and gas prices.

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

Oil and natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic 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.

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.

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 and place us at a competitive disadvantage. For example at December 31, 2006, approximately 57% of our debt is at fixed interest rates with the remaining 43% subject to variable interest rates.

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.

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.

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.

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 not able 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.

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.

A portion of our business is subject to special risks generally related to offshore operations and specifically in the Gulf of Mexico

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial expense and liabilities that could materially reduce the funds available for exploration, development or leasehold acquisitions or result in the loss of equipment and properties. As of February 20, 2007, we continued to have approximately 1.0 Mmcfe per day of production shut-in due to the effects of hurricanes Katrina and Rita.

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

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

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. 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 not able to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Table of Contents

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 $650.0 million to $825.0 million 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;
- the terms of our existing credit arrangements contain numerous financial and other restrictive covenants;
- 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.

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. 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 financial statements are complex

Due to accounting rules, 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 plan. We expect such complexity to continue and possibly increase.

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, 2004 to December 31, 2006, the last daily sale price of our common stock reported by the New York Stock Exchange ranged from a low of $6.25 per share to a high of $31.77 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 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.

Table of Contents

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, 2006:

Division	Average Daily Production (mcfe per day)	Total Production (mcfe)	Percentage of Total Production	Total Proved Reserves (Mmcfe)	Percentage of Total Proved Reserves
Southwest	150,731	55,017,031	55%	774,933	44%
Appalachia	103,032	37,606,463	37%	915,054	52%
Gulf Coast	22,334	8,151,801	8%	68,239	4%
	276,097	100,775,295	100%	1,758,226	100%

Segment reporting is not applicable to us as 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.

Southwest Division

The Southwest Division 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 Division, we own 2,057 net producing wells, 96% of which we operate. Our average working interest is 73%. We have approximately 687,000 gross (480,000 net) acres under lease.

Total proved reserves increased 272.3 Bcfe, or 54%, at December 31, 2006 when compared to year-end 2005. Production was more than offset by property purchases (122.9 Bcfe) and drilling additions (208.2 Bcfe). Annual production increased 29% over 2005. During 2006, the region spent $313.1 million to drill 253.0 (212.0 net) development wells, of which 249.0 (210.2 net) were productive and 4 (1.2 net) exploratory wells, of which 2 (0.2 net) were productive. During the year, the region achieved a 99% drilling success rate.

At December 31, 2006, the Southwest Division had a development inventory of 219 proven drilling locations and 316 proven recompletions. 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 aggressive cost control, upgrading lifting equipment, improving gathering systems and surface facilities and performing restimulations and refracturing operations.

Appalachia Division

Our properties in this division 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 9,306 net producing wells, 69% of which we operate and 4,900 miles of gas gathering lines. Our average working interest is 73%. We have approximately 2.3 million gross (1.9 million net) acres under lease which includes over 70,000 acres associated with royalties.

Reserves at December 31, 2006 increased 76.7 Bcfe, or 9%, from 2005 due to drilling additions (161.8 Bcfe) which were partially offset by a net unfavorable reserve revision and production. Annual production increased 10% over 2005. During 2006, the region spent $184.3 million to drill 739 (477.8 net) development wells, of which 737

(477.0 net) were

Table of Contents

productive and 10 (7.0 net) exploratory wells, of which 9 (6.0 net) were productive. During the year, the region achieved approximately a 100% drilling success rate. At December 31, 2006, the Appalachia Division had an inventory of 3,300 proven drilling locations and 212 proven recompletions.

Gulf Coast Division

The Gulf Coast properties are located onshore in Texas, Louisiana and Mississippi and in the shallow waters of the Gulf of Mexico. The division s wells are characterized by high initial rates and relatively short reserve lives. Over the past several years, we have shifted our focus away from offshore to onshore Gulf of Mexico properties that provide greater operating control, generally lower costs and higher repeatability. Major onshore fields produce from Hartburg formations at depths of 10,000 to 11,000 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 operate a majority of our onshore properties while third parties operate all of our offshore properties. Onshore, we have approximately 102,000 gross (56,000 net) acres under lease. Offshore properties include interests in 37 platforms in water depths ranging from 11 to 240 feet. We own 33 net producing wells in this division, 42% of which we operate. Our average working interest is 23%. Our Gulf Coast Division owns a license to a 3-D seismic database covering over 800 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana.

Reserves increased 2.4 Bcfe, or 4%, from 2005 with production more than offset by drilling additions (9.5 Bcfe) and a favorable reserve revision. On an annual basis, production decreased 23% from 2005. During 2006, the region spent $38.0 million to drill 8 (4.6 net) development wells, of which 6 (2.6 net) were productive and 3 (1.3 net) exploratory wells, of which 1 (0.7 net) was productive. During the year, the division had a 56% drilling success rate. At December 31, 2006, the Gulf Coast Division had an inventory of 13 proven drilling locations and 59 proven recompletions.

Proved Reserves

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

	December 31,				
	2006	2005	2004	2003	2002
Natural gas (Mmcf)					
Developed	875,395	724,876	580,006	344,187	320,224
Undeveloped	560,583	400,534	366,422	142,217	120,043
Total	1,435,978	1,125,410	946,428	486,404	440,267
Oil and NGLs (Mbbls)					
Developed	37,750	33,029	27,715	24,912	17,176
Undeveloped	15,957	13,863	10,451	8,111	5,776
Total	53,707	46,892	38,166	33,023	22,952
Total (Mmcfe) [a]	1,758,226	1,406,762	1,175,425	684,541	577,977
% Developed	63%	66%	64%	72%	73%

(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 the Great Lakes and Pine Mountain acquisitions (see Note 3 to our consolidated financial statements), adding to our future drilling inventory. From 2004 to 2005, our proved undeveloped percentage declined from 36% to 34% as we continued to aggressively drill. 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.

Table of Contents

The following table sets forth summary information by division with respect to estimated proved reserves at December 31, 2006:

	Pre-tax Present Value (a)		Reserve Volumes			
	Amount		Oil & NGL	Natural Gas	Total	
	(In thousands)	%	(Mbbls)	(Mmcf)	(Mmcfe)	%
Southwest	$ 1,407,302	51%	39,859	535,770	774,933	44%
Appalachia	1,181,045	43%	12,183	841,958	915,054	52%
Gulf Coast	183,095	6%	1,665	58,250	68,239	4%
Total	$ 2,771,442	100%	53,707	1,435,978	1,758,226	100%

(a) This measure was prepared using year-end oil and gas prices adjusted for the location and quality of reserves, discounted at 10% per year. Our pre-tax present value of $2.8 billion less discounted taxes of $0.8 billion equals our standardized measure of $2.0 billion. See Note 19 to our consolidated financial statements.

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 history in engineering certain properties. At December 31, 2006, these consultants collectively reviewed approximately 87% 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%.

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

	December 31,				
	2006	2005	2004	2003	2002
Future net revenue	$6,391	$10,429	$5,035	$2,687	$1,817
Present value					
Pre-tax	2,771	4,887	2,396	1,396	965
After tax	2,002	3,384	1,749	1,003	500
Benchmark prices					
Oil price (per barrel)	$61.05	$ 61.04	$43.33	$32.52	$31.17
Gas price (per mcf)	$ 5.64	$ 10.08	$ 6.18	$ 6.19	$ 4.75
Wellhead prices					
Oil price (per barrel)	$57.66	$ 57.80	$40.44	$29.48	$27.52
Gas price (per mcf)	$ 5.24	$ 9.83	$ 6.05	$ 6.03	$ 4.76

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. There can be no assurance that the proved reserves will be produced within the periods indicated and prices and costs will not remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of our reserves have been filed with or included in reports to another federal authority or agency since year-end.

Table of Contents

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2006. We also own royalty interests in an additional 1,991 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.

	Total Wells		Average Working Interest
	Gross	Net	
Crude oil	2,381	2,038	86%
Natural gas	13,330	9,358	70%
Total	15,711	11,396	73%

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

At December 31, 2006, we owned interests in developed and undeveloped oil and gas acreage as set forth in the table below. These ownership interests generally take the form of working interests in oil and gas leases or licenses 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.

The following table sets forth certain information regarding our developed and undeveloped acreage held at December 31, 2006:

	Acres		Average Working Interest
	Gross	Net	
Developed	1,458,500	1,139,185	78%
Undeveloped	1,756,406	1,360,545	77%
Total [(a)]	3,214,906	2,499,730	78%

(a) Includes over 70,000 acres in Appalachia in which we own royalty and overriding royalty interests. Also, does not include 24,000 net acres in the Southwest Division attributable to a farm-in.

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
2007	223,980	179,351	14%
2008	227,172	164,179	13%
2009	280,443	204,338	16%
2010	107,479	88,798	7%
2011	277,866	217,487	17%

Table of Contents

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.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	992.0	689.7	813.0	573.8	436.0	368.5
Dry	8.0	4.6	10.0	7.7	16.0	12.0
Exploratory wells						
Productive	12.0	6.9	13.0	8.1	14.0	9.2
Dry	5.0	2.6	5.0	3.9	10.0	6.9
Total wells						
Productive	1,004.0	696.6	826.0	581.9	450.0	377.7
Dry	13.0	7.2	15.0	11.6	26.0	18.9
Total	1,017.0	703.8	841.0	593.5	476.0	396.6
Success ratio	99%	99%	98%	98%	95%	95%

Real Property

We lease approximately 203,700 square feet of office space, primarily in Texas and Oklahoma under standard office lease arrangements that expire at various dates through 2017. Our Appalachian Division owns a 34,500 square foot office building and various other field offices. In the first half of 2007, our Fort Worth office will be relocating to 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. We believe our facilities are adequate to meet our current needs and existing space could be expanded or additional space could be leased if required. We own various vehicles and other equipment that is used in field operations. We believe such equipment is in good repair and can be readily replaced if necessary.

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 prior to 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 2006.

Table of Contents

PART II

ITEM 5. MARKET FOR 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 2006, trading volume averaged 1.1 million shares per day. The following table shows the quarterly high and low sale prices, cash dividends declared and volumes as reported on the NYSE composite tape for the past two years (as adjusted for a three-for-two stock split effected on December 2, 2005).

	High	Low	Cash Dividends Declared	Average Daily Volumes
2005				
First quarter	$17.59	$12.34	0.0133	1,072,650
Second quarter	18.62	13.50	0.0133	1,334,709
Third quarter	26.33	18.01	0.0133	1,203,888
Fourth quarter	28.37	20.71	0.02	1,565,650
2006				
First quarter	$30.52	$22.52	0.02	1,343,584
Second quarter	30.29	21.74	0.02	1,202,248
Third quarter	30.37	23.38	0.02	884,865
Fourth quarter	31.77	22.80	0.03	895,294

Between January 1, 2007 and February 20, 2007, the common stock traded at prices between $25.29 and $31.25 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 20, 2007, there were approximately 1,967 holders of record of our common stock.

Dividends

In December 2006, the Board of Directors increased our quarterly dividend to $0.03 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 2006.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2006. Significant producing property acquisitions in 2006 and 2004 affect the comparability of year-to-year financial and operating data. 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 (in thousands, except per share data).

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Balance Sheet Data:					
Current assets [(a)]	$ 320,337	$ 207,977	$ 136,336	$ 66,092	$ 50,619
Current liabilities [(b)]	232,356	321,760	177,162	106,964	67,206
Oil and gas properties, net	2,676,676	1,741,182	1,402,359	723,382	564,406
Total assets	3,187,674	2,018,985	1,595,406	830,091	658,484
Bank debt	452,000	269,200	423,900	178,200	115,800
Subordinated debt	596,782	346,948	196,656	109,980	90,901
Stockholders equity[(c)]	1,256,161	696,923	566,340	274,066	206,109
Weighted average dilutive shares outstanding	138,711	129,125	97,998	86,775	81,627
Cash dividends declared per common share	0.09	.0599	.0267	.0067	
Cash Flow Data:					
Net cash provided from operating activities	479,875	325,745	209,249	124,680	114,472
Net cash used in investing activities	911,659	432,377	624,301	186,838	103,950
Net cash provided from (used in) financing activities	429,416	93,000	432,803	61,455	(12,568)

(a) 2005, 2004 and 2003 include deferred tax assets of $61.7 million, $26.3 million and $19.9 million, respectively. 2006 includes a $93.6 million hedging asset.

(b) 2006, 2005, 2004, 2003 and 2002 include hedging liabilities of $4.6 million,

$160.1 million, $61.0 million, $54.3 million and $26.0 million, respectively.

(c) Stockholders equity includes other comprehensive income (loss) of $36.5 million, ($147.1 million), ($43.3 million), ($42.9 million) and ($21.2 million) in 2006, 2005, 2004, 2003 and 2002, respectively.

Table of Contents

Statement of Operations Data:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Revenues					
Oil and gas sales	$ 683,928	$ 525,074	$ 315,703	$ 226,402	$ 190,954
Transportation and gathering	2,507	2,461	2,202	3,509	3,495
Gain (loss) on retirement of securities			(39)	18,526	3,098
Mark-to-market on oil and gas derivatives	86,491	10,868			
Other	6,802	(2,563)	2,841	(2,670)	(5,958)
Total revenue	779,728	535,840	320,707	245,767	191,589
Costs and expenses					
Direct operating	92,224	67,112	46,308	36,423	31,869
Production and ad valorem taxes	36,915	31,516	20,504	12,894	8,574
Exploration	45,252	30,604	21,243	13,946	11,525
General and administrative	49,886	33,444	20,610	17,818	16,217
Deferred compensation plan	6,873	29,474	19,176	6,559	1,023
Interest expense and dividends on trust preferred	57,577	38,797	23,119	22,165	23,153
Depletion, depreciation and amortization	167,262	127,514	99,408	86,549	76,820
Provision for impairment	2,399		3,563		
Total costs and expenses	458,388	358,461	253,931	196,354	169,181
Income from continuing operations before income taxes and accounting change	321,340	177,379	66,776	49,413	22,408
Income tax provision (benefit)					
Current	1,912	1,071	(245)	170	(4)
Deferred	121,814	65,297	24,790	18,319	(3,354)
	123,726	66,368	24,545	18,489	(3,358)
Income from continuing operations	197,614	111,011	42,231	30,924	25,766
Loss from discontinued operations	(38,912)				
Income before cumulative effect of changes in accounting principles	158,702	111,011	42,231	30,924	25,766
Cumulative effect of changes in accounting principles, net of taxes				4,491	

Net income	158,702	111,011	42,231	35,415	25,766
Preferred dividends			(5,163)	(803)	
Net income available to common stockholders	$ 158,702	$ 111,011	$ 37,068	$ 34,612	$ 25,766
Earnings per common share:					
Basic income from continuing operations	$ 1.48	$ 0.89	$ 0.40	$ 0.37	$ 0.32
loss from discontinued operations	(0.29)				
cumulative effect of changes in accounting principles				0.05	
Net income	$ 1.19	$ 0.89	$ 0.40	$ 0.42	$ 0.32
Diluted income from continuing operations	$ 1.42	$ 0.86	$ 0.38	$ 0.36	$ 0.32
loss from discontinued operations	(0.28)				
cumulative effect of changes in accounting principles				0.05	
Net income	$ 1.14	$ 0.86	$ 0.38	$ 0.41	$ 0.32

Table of Contents

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.

Overview of Our Business

We are an independent natural gas and oil 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.

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 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 Divisions, 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 natural 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 2007. In addition, we expect drilling and service costs to remain at a high level in 2007 and for lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Natural 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 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 natural gas and oil that is produced from our properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. 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 utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas and oil production. During 2006, 2005 and 2004 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.

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 not covered by insurance. These costs are expected to remain high in 2007 as the demand for these services continues to increase. Direct operating expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R), amortization of restricted stock grants and mark-to-market of SARs as part of employee compensation.

Production and Ad Valorem Taxes. These costs are primarily paid based on a percentage of market prices and not on hedged prices of production or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. Geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory wells or dry holes. Exploration expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R), amortization of restricted stock grants and mark-to-market of SARs 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), amortization of restricted stock grants and mark-to-market of SARs 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 public traded debt securities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We may continue to incur significant interest expense as we continue to grow. We expect our 2007 capital budget to be funded with internal cash flow and asset sales.

Depreciation, Depletion and Amortization. The systematic expensing of the capital 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 also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

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, all of our federal taxes are deferred; however, at some point, we will utilize 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.

Management s Discussion and Analysis of Income and Operations

Volumes and Price Data

	2006	2005	2004
Production:			
Crude oil (bbls)	3,159,623	3,031,468	2,512,434
NGLs (bbls)	1,091,785	1,011,692	988,192
Natural gas (mcf)	75,266,847	63,003,600	50,722,121
Total (mcfe) [a]	100,775,295	87,262,560	71,725,877
Average daily production:			
Crude oil (bbls)	8,656	8,305	6,865
NGLs (bbls)	2,991	2,772	2,700
Natural gas (mcf)	206,210	172,613	138,585
Total (mcfe) [a]	276,097	239,076	195,972
Average sales prices (excluding hedging):			
Crude oil (per bbl)	$ 62.60	$ 53.31	$ 39.25
NGLs (per bbl)	33.62	31.52	23.73
Natural gas (per mcf)	6.58	7.98	5.79
Total (per mcfe) [a]	7.25	7.98	5.80
Average sales prices (including hedging):			
Crude oil (per bbl)	$ 47.27	$ 38.71	$ 28.04
NGLs (per bbl)	33.62	27.27	19.76
Natural gas (per mcf)	6.61	6.03	4.45
Total (per mcfe) [a]	6.79	6.02	4.40
Average NYMEX prices [b]			
Oil (per bbl)	$ 66.22	$ 56.56	$ 41.42
Natural gas (per mcf)	7.26	8.55	6.09

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

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

Table of Contents

Overview of 2006 Results

During 2006, we achieved the following results:

- 15% production growth and 25% reserve growth;
- Drilled over 700 net wells;
- Continued expansion of drilling inventory and emerging plays;
- Record financial results and continued balance sheet improvement; and
- Completed an acquisition of properties containing 171 Bcfe of proved reserves.

Our 2006 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 represents an ongoing challenge for management. During periods of historically high oil and gas prices, such as 2005 and 2006, drilling service and operating cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2006 including attracting and retaining qualified personnel, consummating and integrating acquisitions, and accessing the capital markets to fund our growth and capital simplification process 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 build, providing new growth opportunities, greater diversification of technical risk and better efficiency.

Total revenues increased 46% in 2006 over the same period of 2005. This increase is due to higher production and realized oil and gas prices. Our 2006 production growth is due to acquisitions completed in 2006 and to the continued success of our drilling program. Realized prices were higher by 13% in 2006 reflecting the expiration of lower priced oil and gas hedges. 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, particularly on the fair value of our derivatives.

Comparison of 2006 to 2005

Oil and gas revenue for the years ended December 31, 2006 and 2005 (in thousands) is summarized in the following table:

	2006	2005	Change	%
Revenues:				
Oil wellhead	$ 197,815	$ 161,627	$ 36,188	22%
Oil hedges	(48,445)	(44,273)	(4,172)	9%
Total oil revenue	$ 149,370	$ 117,354	$ 32,016	27%
Gas wellhead	$ 495,920	$ 502,691	$ (6,771)	1%
Gas hedges	1,934	(122,560)	124,494	102%
Total gas revenue	$ 497,854	$ 380,131	$ 117,723	31%
NGL	$ 36,704	$ 31,891	$ 4,813	15%
NGL hedges		(4,302)	4,302	100%

Total NGL revenue	$ 36,704	$ 27,589	$ 9,115	33%
Combined wellhead	$ 730,439	$ 696,209	$ 34,230	5%
Combined hedges	(46,511)	(171,135)	124,624	73%
Total oil and gas revenue	$ 683,928	$ 525,074	$ 158,854	30%

Average realized price received for oil and gas during 2006 was $6.79 per mcfe, up 13% or $0.77 per mcfe from 2005. Oil and gas revenues for 2006 reached a record $683.9 million and were 30% higher than 2005 due to higher realized oil and gas prices and a 15% increase in production. The average price received increased 22% to $47.27 per barrel for oil and increased 10% to $6.61 per mcf for gas from 2005. The effect of our hedging program decreased realized prices $0.46 per mcfe in 2006 versus a decrease of $1.96 in 2005.

Production volumes increased 15% from 2005 due to continued drilling success and additions from acquisitions consummated in 2006. Production increased 13.5 Bcfe from 2005. Our production volumes increased 10% in our Appalachia Division, increased 29% in our Southwest Division and declined 22% in our Gulf Coast Division.

Mark-to-market on oil and gas derivatives includes a gain of $86.5 million in 2006. 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.

Other revenue increased in 2006 to a gain of $6.8 million from a loss of $2.6 million in 2005. The 2006 period includes $6.0 million of ineffective hedging gains and income from equity method investments of $548,000. The 2005 period includes ineffective hedging losses of $3.4 million.

Our operating expenses have increased as we continue to grow. We believe most of our operating expense fluctuations should be analyzed on a unit-of-production, or per mcfe basis.

The following table presents information about our operating expenses on an mcfe basis for 2006 and 2005:

Operating expenses per mcfe	2006	2005	Change	%
Direct operating expense (excluding $0.01 per mcfe stock-based compensation in 2006)	$0.90	$0.76	$0.14	18%
Production and ad valorem tax expense	0.37	0.36	0.01	3%
General and administrative expense (excluding stock-based compensation of $0.14 per mcfe in 2006 and $0.06 per mcfe in 2005)	0.35	0.33	0.02	6%
Interest expense	0.57	0.44	0.13	30%
Depletion, depreciation and amortization expense (excluding impairment)	1.66	1.46	0.20	14%

Direct operating expense (excluding stock-based compensation) increased $24.2 million to $90.8 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. We incurred $6.7 million of expenses associated with workovers in 2006 versus $7.4 million in 2005. In 2006, 54% of our workover expenses were incurred by our Gulf Coast division and were primarily hurricane related. In 2005, 58% of our workover expenses were incurred by our Gulf Coast Division and were primarily hurricane related. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) were $0.90 per mcfe and increased $0.14 per mcfe from 2005 with the increase consisting primarily of higher offshore well insurance ($0.02 per mcfe), higher utilities ($0.02 per mcfe), and higher water disposal and equipment costs ($0.06 per mcfe).

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $5.4 million, or 17%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes increased from $0.36 per mcfe in 2005 to $0.37 per mcfe in 2006 due to higher market prices.

General and administrative expense (excluding stock-based compensation) for 2006 increased 25%, or $7.0 million, due to higher salaries and benefits ($6.0 million) and higher office rent and general office expense ($1.0 million). On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased from $0.33 per mcfe in 2005 to $0.35 per mcfe in 2006.

Interest expense for 2006 increased $18.8 million, or 48%, to $57.6 million with higher average interest rates, higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In 2006, we issued $250.0 million of 7.5% senior subordinated notes which added $9.7 million of interest costs. The proceeds from this issuance were used to retire shorter term bank debt. In 2006, the average debt outstanding on the bank credit facility was $347.8 million with an average interest rate of 6.4% compared to an average debt outstanding in 2005 of $314.8 million with an average interest rates of 4.5%.

Table of Contents

Depletion, depreciation and amortization, (DD&A), increased $42.1 million, or 33%, due to higher production and higher depletion rates. DD&A (excluding impairment) increased from $1.46 per mcfe in 2005 to $1.66 per mcfe in 2006. 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. In 2006, we also recorded impairment of $2.4 million on an offshore property due to declining oil and gas prices which added $0.02 per mcfe. For 2007, based on our current reserve base, we expect our DD&A rate to average approximately $1.87 per mcfe. The increase in DD&A per mcfe is related to our Stroud acquisition, increasing drilling costs and the mix of our production.

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 2006, stock-based compensation is a component of direct operating expense ($1.4 million), exploration expense ($3.1 million), general and administrative expense ($14.3 million) and a $320,000 reduction of gas transportation revenues for a total of $19.1 million. In 2005, stock-based compensation is equal to $480,000 included in direct operating, $1.2 million included in exploration expense, $4.9 million included in general and administrative expense and a reduction of $117,000 of gas transportation revenues for a total of $6.7 million. This expense represents the amortization of restricted stock grants in 2006 and 2005, expenses related to the adoption of SFAS No. 123(R) in 2006 and in 2005, the mark-to-market of SARs granted to employees. The increase in stock-based compensation in 2006 is the result of adopting SFAS No. 123(R) which requires expensing of stock options.

Exploration expense increased 48% to $45.3 million due to higher seismic costs ($1.6 million), higher dry hole costs ($9.1 million) and higher personnel costs. The following table details our exploration-related expenses (in thousands):

Exploration expenses	2006	2005	Change	%
Dry hole expense	$ 16,103	$ 7,045	$ 9,058	129%
Seismic	15,412	13,844	1,568	11%
Personnel expense	6,917	5,872	1,045	18%
Stock-based compensation expense	3,079	1,250	1,829	146%
Other	3,741	2,593	1,148	44%
Total exploration expense	$ 45,252	$ 30,604	$ 14,648	48%

Deferred compensation plan expense decreased 77%, or $22.6 million from 2005. 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. Our common stock price increased from $13.64 per share at the end of 2004 to $26.34 per share at the end of 2005 to $27.46 per share at the end of 2006.

Income tax expense for 2006 increased $57.4 million, or 86%, over 2005 due to a 81% increase in income from continuing operations. Our effective tax rate was 39% for 2006 and was 37% for 2005. The twelve months ended December 31, 2006 includes a $2.8 million adjustment for changes in state tax rates. Given our available net operating loss carryforward, we do not expect to pay significant federal income taxes. We paid $1.8 million of state income taxes in 2006.

Discontinued operations includes the operating results and impairment losses on the Austin Chalk properties which were acquired as part of the Stroud transaction. See also Note 4 to our consolidated financial statements. Due to significant price declines subsequent to the purchase of these properties and volumes produced since the acquisition, we recognized impairment of $74.9 million. These properties were sold on February 13, 2007 for proceeds of $80.4 million.

Table of Contents

Comparison of 2005 to 2004

Oil and gas revenue for the years ended December 31, 2005 and 2004 (in thousands) is summarized in the following table:

	2005	2004	Change	%
Revenues				
Oil wellhead	$ 161,627	$ 98,608	$ 63,019	64%
Oil hedges	(44,273)	(28,169)	(16,104)	57%
Total oil revenue	$ 117,354	$ 70,439	$ 46,915	67%
Gas wellhead	$ 502,691	$ 293,769	$ 208,922	71%
Gas hedges	(122,560)	(68,031)	(54,529)	80%
Total gas revenue	$ 380,131	$ 225,738	$ 154,393	68%
NGL	$ 31,891	$ 23,446	$ 8,445	36%
NGL hedges	(4,302)	(3,920)	(382)	10%
Total NGL revenue	$ 27,589	$ 19,526	$ 8,063	41%
Combined wellhead	$ 696,209	$ 415,823	$ 280,386	67%
Combined hedges	(171,135)	(100,120)	(71,015)	71%
Total oil and gas revenue	$ 525,074	$ 315,703	$ 209,371	66%

Average realized price received for oil and gas during 2005 was $6.02 per mcfe, up 37% or $1.62 per mcfe from 2004. Oil and gas revenues for 2005 reached a record $525.1 million and were 66% higher than 2004 due to higher oil and gas prices and a 22% increase in production. The average price received in 2005 increased 38% to $38.71 per barrel for oil and increased 36% to $6.03 per mcf for gas. The effect of our hedging program decreased realized prices $1.96 per mcfe in 2005 versus a decrease of $1.40 in 2004.

Production volumes increased 22% from 2004 due to our drilling program and additions from acquisitions consummated in 2004, primarily our purchase of the 50% of Great Lakes that we did not own and Pine Mountain. Production increased 15.5 Bcfe from 2004. Our production volumes increased 69% in our Appalachia Division, increased 14% in our Southwest Division and declined 26% in our Gulf Coast Division.

Transportation and gathering revenue of $2.5 million increased $259,000 from 2004. This increase is primarily due to higher gas prices and additional throughput volumes offset by lower oil marketing revenue.

Mark-to-market on oil and gas derivatives includes a gain of $10.9 million in 2005. In the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices.

Other revenue declined in 2005 to a loss of $2.6 million from a gain of $2.8 million in 2004. The 2005 period includes ineffective hedging losses due to widening basis differentials of $3.4 million. The 2004 period includes a gain on the sale of properties of $5.0 million and $712,000 of ineffective hedging gains offset by $2.0 million write-down of an insurance claim receivable.

The following table presents information about our operating expenses that generally trend with changes in production for 2005 and 2004:

Operating expenses per mcfe	2005	2004	Change	%
Direct operating expense (excluding stock-based compensation)	$0.76	$0.65	$0.11	17%
Production and ad valorem tax expense	0.36	0.29	0.07	24%
General and administration expense (excluding stock-based compensation of $0.06 per mcfe in 2005)	0.33	0.28	0.05	18%
Interest expense	0.44	0.32	0.12	38%
Depletion, depreciation and amortization expense (excluding impairment)	1.46	1.39	0.07	5%

Table of Contents

Direct operating expense (excluding stock-based compensation) increased $20.3 million to $66.6 million due to increased costs from acquisitions, higher oilfield service costs and higher workover costs primarily in our Gulf Coast Division. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $7.4 million of expenses associated with workovers in 2005 versus $1.8 million in 2004. In 2005, 58% of our workover expenses were incurred by our Gulf Coast Division and were primarily hurricane related. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) were $0.76 per mcfe and increased 17% or $0.11 per mcfe from 2004 consisting of higher field level costs ($0.04 per mcfe) and higher workover costs ($0.07 per mcfe).

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $11.0 million, or 54%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes increased from $0.29 per mcfe to $0.36 per mcfe due to higher market prices.

General and administrative expense (excluding stock-based compensation) for 2005 increased 42%, or $8.5 million, from 2004 with additional personnel costs due to the Great Lakes and Pine Mountain acquisitions ($1.8 million), higher salaries and benefits ($3.5 million), higher legal expenses ($1.3 million) and a $725,000 legal settlement accrual. On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased 17% from $0.28 per mcfe in 2004 to $0.33 per mcfe in 2005.

Interest expense for 2005 increased $15.7 million, or 68%, to $38.8 million with higher average interest rates, higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In March 2005, we issued $150.0 million of 6.375% senior subordinated notes which added $7.8 million of interest costs. The proceeds from this issuance were used to retire lower interest bank debt. Average debt outstanding on the bank credit facility was $314.8 million and $296.6 million for 2005 and 2004, respectively, and the average interest rates were 4.3% and 3.5%, respectively.

Depletion, depreciation and amortization (DD&A) increased $24.5 million, or 24%, due to higher production and higher depletion rates. DD&A increased from $1.39 per mcfe in 2004 to $1.46 per mcfe in 2005. The twelve months ended December 31, 2004 includes a $3.6 million impairment charge on an offshore property in our Gulf Coast Division.

Operating expenses also include stock-based compensation, exploration expense and non-cash compensation expense that generally do not trend with production. In 2005, stock-based compensation expense is a component of direct operating expense ($480,000), exploration expense ($1.2 million) and general and administrative expense ($4.9 million). This expense represents the amortization of restricted stock grants and the market-to-market of SARs granted to employees. In 2004, stock-based compensation is a component of exploration expense ($24,000) and general and administrative expense ($541,000).

Exploration expense increased 44% to $30.6 million due to higher seismic costs ($10.5 million), higher personnel costs, higher stock-based compensation expense ($1.2 million), partially offset by lower dry hole costs ($5.0 million).

Exploration expenses	2005	2004	Change	%
Dry hole expense	$ 7,045	$ 12,096	$ (5,050)	42%
Seismic	13,844	3,329	10,515	316%
Personnel expense	5,872	4,451	1,421	32%
Stock-based compensation expense	1,250	24	1,226	5108%
Other	2,593	1,343	1,249	93%
Total exploration expense	$ 30,604	$ 21,243	$ 9,361	44%

Deferred compensation plan expense increased 53%, or $10.3 million, from 2004. This non-cash expense relates to the increase in value of our common stock and other investments held in our deferred compensation plans. Our common stock price increased from $13.64 per share at the end of 2004 to $26.34 per share at the end of 2005.

Tax expense for 2005 increased $41.8 million, or 170%, over 2004 due to a 166% increase in income before taxes. Our effective tax rate for 2005 and 2004 was 37%. Given our available net operating loss carryforward, we do not expect to pay significant federal income taxes.

Table of Contents

Management s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

During 2006, our cash provided from continuing operations was $467.6 million, and we spent $898.6 million on capital expenditures (including acquisitions). During this period, financing activities provided net cash of $429.4 million. Our financing activities included the sale of $250.0 million of 7.5% senior subordinated notes and additional borrowings under our bank credit agreement. At December 31, 2006 we had $2.4 million in cash, total assets of $3.2 billion and a debt-to-capitalization ratio of 45.5%. Long-term debt at December 31, 2006 totaled $1.0 billion, including $452.0 million of bank debt and $596.8 million of senior subordinated notes. Available borrowing capacity under the bank credit facility at December 31, 2006 was $348.0 million.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves which is typical in the oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities and unused committed borrowing capacity under the bank credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proved reserves.

Bank Debt

We maintain an $800.0 million revolving credit facility, which we refer to as our bank debt or our bank credit facility. The bank credit facility is secured by substantially all of our assets and matures on October 25, 2011. Availability under the bank credit facility is subject to a borrowing base set by the banks semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors, primarily the lenders assessment of future cash flows. Redeterminations of the borrowing base require approval of 75% of the lenders; increases require unanimous approval. At February 22, 2007, the bank credit facility had a $1.2 billion borrowing base and an $800.0 million facility amount. Credit availability is equal to the lesser of the facility amount or the borrowing base resulting in credit availability of $287.0 million on February 20, 2007. The facility amount can be increased to the borrowing base with twenty days notice.

Limitations on the payment of dividends and other restricted payments as defined are imposed under our bank debt and our subordinated notes. Under the bank credit facility, common and preferred dividends are permitted. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. At December 31, 2006, approximately $496.2 million was available under the restricted payment baskets for each of our subordinated notes. The bank credit facility provides for a restricted payment basket of $20.0 million plus 66-2/3% of net cash proceeds from common stock issuances and 50% of net income. Approximately $446.4 million was available under the bank credit facility restricted payment basket as of December 31, 2006. The debt agreements contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2006.

Cash Flow

Our principal sources of cash are operating cash flow, bank borrowings and at times, issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of December 31, 2006, we had entered into hedging agreements covering 84.9 Bcfe and 71.7 Bcfe for 2007 and 2008. The $538.4 million of cash capital expenditures for 2006, excluding acquisitions, was funded with internal cash flow and borrowing under the bank credit facility. The $698.0 million capital budget for 2007, which excludes acquisitions, is expected to increase production and to expand the reserve base. Based on current projections, oil and gas futures prices and our hedge position, the 2007 capital program is expected to be funded with internal cash flow and asset sales.

Net cash provided from continuing operations in 2006 was $467.6 million, compared with $325.7 million in 2005 and $209.2 million in 2004. In 2006, cash flow from continuing operations increased due to higher production volumes and higher realized prices partially offset by increasing operating costs. In 2005, cash flow from operations increased due to higher production volumes and prices partially offset by increasing operating, exploration and interest expenses. In 2004, cash flow from operations increased due to higher volumes and prices partially offset by increasing operating costs.

Net cash used in investing activities in 2006 was $911.7 million, compared with $432.4 million in 2005 and $624.3 million in 2004. In 2006, we spent $502.9 million in additions to oil and gas properties and $360.1 million on acquisitions. The 2005 period included $276.9 million in additions to oil and gas properties and $153.6 million of acquisitions. The 2004 period included $166.6 million in additions to oil and gas properties and $485.6 million of acquisitions.

Net cash provided from financing activities in 2006 was $429.4 million compared with $93.0 million in 2005 and $432.8 million in 2004. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2006, we received proceeds of $249.5 million from the issuance of our 7.5% Notes. During 2005, we received proceeds of $150.0 million and $109.2 million from the issuance of our 6.375% Notes and a common stock offering. During 2005, the outstanding balance under our bank credit facility declined $154.7 million primarily due to the proceeds received from the 6.375% Notes being applied to our bank debt. During 2004, we received proceeds of $98.1 million and $246.1 million from the issuance of additional 7.375% Notes and two common stock offerings, respectively. During 2004, the outstanding balance under our bank credit facility increased $245.7 million with $70.0 million related to the Great Lakes acquisition and the remaining increase the result of funding other acquisitions. Also in 2004, we redeemed the remaining outstanding 6% Debentures for $11.6 million.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2006, $502.9 million of capital was expended on drilling projects. Also in 2006, $360.1 million was expended on acquisitions primarily to purchase producing properties. The capital program, excluding acquisitions, was funded by net cash flow from operations and borrowings under our credit facility and our acquisitions were funded primarily with proceeds received from the issuance of our 7.5% Notes and borrowings under our credit facility. The 2007 capital budget of $698.0 million, excluding acquisitions, is expected to be funded by cash flow from operations and asset sales. In February 2007, we sold the Austin Chalk properties for proceeds of $80.4 million. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to internal cash flow and asset sales. To the extent capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. The Stroud acquisition included the issuance of 6.5 million shares and the assumption of $106.7 million of debt. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Cash Dividend Payments

The amount of future dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors, such as restrictions under our bank debt and our subordinated notes. In 2006, we paid $12.2 million in dividends to our common shareholders ($0.03 per share in the fourth quarter and $0.02 per share in the third, second and first quarters). In 2005, we paid $7.6 million in dividends to our common stockholders ($0.02 per share in the fourth quarter and $0.0133 per share in the third, second and first quarters). In 2004, we paid $3.2 million in dividends to our common stockholders ($0.0067 per share in the second and third quarters and $0.0133 per share in the fourth quarter). Also in 2005 and 2004, we paid $2.2 million and $2.9 million in preferred stock dividends.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2006, we do not have any capital leases nor have we entered into any material long-term contracts for equipment. As of December 31, 2006, we do not have any off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2006. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2006 reflects accrued interest payable on our bank debt of $925,000 which is payable in January 2007. We expect to make

Table of Contents

annual interest payments of $14.8 million per year on our 7.375% Notes, $18.8 million per year on our 7.5% Notes and payments of $9.6 million per year on our 6.375% Notes.

The following summarizes our contractual financial obligations at December 31, 2006 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under the bank credit facility and proceeds from asset sales proceeds.

	Payment due by period				
	2007	2008 and 2009	2010 and 2011	Thereafter	Total
			(in thousands)		
Bank debt due 2011	$	$	$ 452,000 (a)	$	$ 452,000
7.375% senior subordinated notes due 2013				200,000	200,000
6.375% senior subordinated notes due 2015				150,000	150,000
7.5% senior subordinated notes due 2016				250,000	250,000
Operating leases	5,010	10,236	6,431	9,610	31,287
Drilling contracts	12,830	2,160			14,990
Service contracts	1,794	3,705	2,754		8,253
Derivative obligations (b)	4,621	266			4,887
Asset retirement obligation liability	4,193	8,674	8,423	74,298	95,588
Total contractual obligations (c)	$ 28,448	$ 25,041	$ 469,608	$ 683,908	$ 1,207,005

(a) Due at termination date of our bank credit facility, which we expect to renew, but there is no assurance that can be accomplished. Interest paid on our bank credit facility would be approximately $28.9 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contracts valued as of December 31, 2006.

(c) This table does not include the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

Hedging Oil and Gas Prices

We enter into derivative agreements to reduce the impact of oil and gas price volatility on our operations. At December 31, 2006, swaps were in place covering 73.6 Bcf of gas at prices averaging $9.29 per mcf. We also had collars covering 56.1 Bcf of gas at weighted average floor and cap prices of $7.42 to $10.49 and 4.5 million barrels of oil at weighted average floor and cap prices of $55.72 to 70.11. The derivative fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax gain of $149.8 million at December 31, 2006. The contracts expire monthly through December 2008. Transaction gains and losses are determined monthly and are included as increases or decreases on oil and gas revenue in the period the hedged production is sold. Realized hedging losses of $46.5 million were recognized in 2006 compared to losses of $171.1 million in 2005 and losses of $100.1 million in 2004. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly in other revenue. Unrealized effective gains and losses on hedging positions are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on our consolidated balance sheet as other comprehensive income (OCI) a component of stockholders equity. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the effect of volatility of gas prices in the fourth quarter of 2005 and on the correlation between realized prices and hedge reference prices. These derivatives were marked-to-market in the amount of a gain of $10.9 million in the fourth quarter of 2005 and as a gain of $86.5 million in the year ended December 31, 2006.

Table of Contents

At December 31, 2006, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2007	Swaps	96,336 Mmbtu/day	$9.13
2007	Collars	98,500 Mmbtu/day	$7.13 - $9.99
2008	Swaps	105,000 Mmbtu/day	$9.42
2008	Collars	55,000 Mmbtu/day	$7.93 - $11.39
Crude Oil			
2007	Collars	6,300 bbl/day	$53.46 - $65.33
2008	Collars	6,000 bbl/day	$58.09 - $75.11

Interest Rates

At December 31, 2006, we had $1.0 billion of debt outstanding. Of this amount, $600.0 million bears interest at fixed rates averaging 7.2%. Bank debt totaling $452.0 million bears interest at floating rates, which averaged 6.4% at year-end 2006. The 30-day LIBOR rate on December 31, 2006 was 5.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2006 would cost us approximately $4.5 million in additional annual interest.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource position, or for any other purpose.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated during 2005 and 2006, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These costs trends have put pressure not only on our operating costs but also on our capital costs. We expect further increases in these costs for 2007.

Table of Contents

The following table indicates the average oil and gas prices received over the last five years and quarterly for 2006, 2005 and 2004. Average price calculations exclude hedging gains and losses. Oil is converted to natural gas equivalent at the rate of one barrel equals six mcfe.

	Average Prices (Excluding Hedging)			Average NYMEX Prices [(a)]	
	Oil (Per bbl)	Natural Gas (Per mcf)	Equivalent Mcf (Per mcfe)	Oil (Per bbl)	Natural Gas (Per mcf)
Annual					
2006	$62.60	$ 6.58	$ 7.25	$66.22	$ 7.26
2005	53.31	7.98	7.98	56.56	8.55
2004	39.25	5.79	5.80	41.42	6.09
2003	28.42	5.10	4.94	31.04	5.44
2002	23.34	3.02	3.16	26.08	3.25
Quarterly					
2006					
First	$59.80	$ 8.29	$ 8.39	$63.48	$ 9.07
Second	66.25	6.30	7.19	70.70	6.82
Third	64.69	6.12	7.00	70.48	6.53
Fourth	59.68	5.89	6.57	60.21	6.62
2005					
First	$47.09	$ 5.97	$ 6.24	$49.84	$ 6.32
Second	48.79	6.42	6.65	53.17	6.80
Third	59.90	7.88	8.17	63.19	8.25
Fourth	56.39	11.30	10.57	60.02	12.85
2004					
First	$32.15	$ 5.21	$ 5.10	$35.15	$ 5.69
Second	35.87	5.56	5.49	38.32	5.97
Third	40.99	5.59	5.70	43.88	5.84
Fourth	45.85	6.66	6.72	48.23	6.87

(a) Based on average of bid week prompt month prices.

Management s Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Oil and Gas Properties

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Vice President of Reservoir Engineering who reports directly to our Chief Operating Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to review our estimates of proved reserves. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%.

The following table sets forth a summary of the percent of reserves which were reviewed by independent petroleum consultants for each of the years ended 2006, 2005 and 2004.

	Audited[(a)]	
2006	2005	2004
87%	84%	88%

(a) Audited reserves are those reserves estimated by our employees and reviewed by an independent petroleum consultant.

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and gas reserves as estimated by our engineers and reviewed by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Otherwise, well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year following completion of drilling and these criteria are not met. Proven property leasehold costs are charged to expense using the units of production method based on total proved reserves. Unproved properties are assessed periodically (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

We adhere to the Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated (at least annually) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $226.3 million in 2006 compared to $28.6 million in 2005 and $14.8 million in 2004.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to oil and gas producing activities and reserve quantities in Note 19, Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities to our consolidated financial statements. Changes in the estimated reserves are considered in estimates for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property s carrying value for impairment. We cannot predict whether impairment charges may be required in the future.

We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to the consolidated financial statements for information on these acquisitions.

Derivatives

We use commodity derivative contracts to manage our exposure to oil and gas price volatility. We account for our commodity derivatives in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. For derivative contracts designated as hedges, earnings are affected by the ineffective portion of a hedge contract (changes in realized prices that do not match the changes in the hedge price). Ineffective gains or losses are recorded in other revenue while the hedge contract is open and may increase or reverse until settlement of the contract. This may result in significant volatility to current period income. For derivatives qualifying as hedges, the effective portion of any changes in fair value is recognized in stockholders equity as other comprehensive income (OCI), and then reclassified to earnings, in oil and gas revenue, when the hedged transaction is consummated. This may result in significant volatility in stockholders equity. The fair value of open hedging contracts is an estimated amount that could be realized upon termination. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the volatility of gas prices and their effect on our basis differentials and are marked-to-market.

The commodity derivatives we use include commodity collars and swaps. While there is a risk that the financial benefit of rising prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Table of Contents

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, (ARO), a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in our consolidated statement of operations.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit which can take years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned. At year-end 2005, deferred tax liabilities exceeded deferred tax assets by $113.1 million, with $85.5 million of deferred tax assets related to unrealized deferred hedging losses included in OCI. At year-end 2006, deferred tax liabilities exceeded deferred tax assets by $468.6 million, with $21.3 million of deferred tax liabilities related to unrealized hedging gains included in OCI.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Accounting Standards Not Yet Adopted

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Range, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In July 2006, FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109 was issued. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. For Range, the provisions of FIN 48 are effective January 1, 2007. The cumulative effect of adopting FIN 48 will be recorded in retained earnings. Range is currently evaluating the provisions of FIN 48 to determine the impact on its consolidated financial statements but we do not expect a material impact on our financial position or results of operations.

ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Market Risk

Our major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars which assume a minimum floor price and a predetermined ceiling price. The majority of our derivatives qualify as accounting hedges. In times of increasing price volatility, we may experience losses from our hedging arrangements and increased basis differentials at the delivery points where we market our production. Widening basis differentials occur when the physical delivery market prices do not increase proportionately to the increased prices in the financial trading markets. Realized gains and losses are recognized in oil and gas revenues when the associated production occurs. Gains or losses on open contracts are recorded either in current period income or other comprehensive income. Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying physical commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Ineffective gains and losses are recognized in earnings as a component of other revenue. We do not enter into derivative instruments for trading purposes. Though not all of our derivatives qualify as accounting hedges, the purpose of entering into the contracts is to economically hedge oil and gas prices. Those that do not qualify as accounting hedges are marked to market through earnings.

As of December 31, 2006, we had oil and gas swaps in place covering 73.6 Bcf of gas. We also had collars covering 56.1 Bcf of gas and 4.5 million barrels of oil. These contracts expire monthly through December 2008. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2006, approximated a net pre-tax gain of $149.8 million. Gains or losses realized on hedging transactions are determined monthly based upon the difference between contract price received by us for the sale of our hedged production and the hedge price, generally closing prices on the NYMEX. These gains and losses are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. In 2006, pre-tax losses were realized in the amount of $46.5 million compared to losses of $171.1 million in 2005 and losses of $100.1 million in 2004. Gains and losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues in our consolidated statement of operations. The ineffective portion of hedges that qualified for hedge accounting was a gain of $6.0 million in 2006 compared to a loss of $3.4 million in 2005 and a gain of $712,000 in 2004.

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity prices changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the volatility in gas prices and its effect on our basis differentials and are marked-to-market. This resulted in a gain of $10.9 million in the fourth quarter of 2005 compared to a gain of $86.5 million in the year ended December 31, 2006 in the income statement category called mark-to-market on oil and gas derivatives.

38

Table of Contents

At December 31, 2006, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2007	Swaps	96,336 Mmbtu/day	$9.13
2007	Collars	98,500 Mmbtu/day	$7.13 - $9.99
2008	Swaps	105,000 Mmbtu/day	$9.42
2008	Collars	55,000 Mmbtu/day	$7.93 - $11.39
Crude Oil			
2007	Collars	6,300 bbl/day	$53.46 - $65.33
2008	Collars	6,000 bbl/day	$58.09 - $75.11

In 2006, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $73.4 million. If oil and gas futures prices at December 31, 2006 had declined by 10%, the unrealized hedging gain at that date would have increased $74.8 million.

Interest Rate Risk

At December 31, 2006, we had $1.0 billion of debt outstanding. Of this amount, $600.0 million bears interest at a fixed rate averaging 7.2%. Bank debt totaling $452.0 million bears interest at floating rates, which averaged 6.4% on that date. On December 31, 2006, the 30-day LIBOR rate was 5.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2006 would cost us approximately $4.5 million in additional annual interest rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For financial statements required by Item 8, see Item 15 in Part IV of this report.

ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in 13a-15(e) of the Securities Exchange Act of 1934, or the Exchange Act). Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Management s Annual Report on Internal Control over Financial Reporting and Attestation Report of Registered Public Accounting Firm. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2006. Ernst & Young, LLP, our registered public accountants, also attested to, and reported on, management s assessment of the effectiveness of internal control over financial reporting. Management s report and the independent public accounting firms attestation report are included in our 2006 Financial Statements in Item 15 under the captions Management s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2006 annual stockholders meeting. Officers are appointed by our board of directors.

	Age	Office Held Since	Position
Charles L. Blackburn	79	2003	Director, Chairman of the Board
Anthony V. Dub	57	1995	Director
V. Richard Eales	70	2001	Director
Allen Finkelson	60	1994	Director
Jonathan S. Linker	58	2002	Director
Kevin S. McCarthy	47	2005	Director
John H. Pinkerton	52	1990	Director, President, Chief Executive Officer
Jeffrey L. Ventura	49	2003	Director, Executive Vice President Chief Operating Officer
Steven L. Grose	58	2005	Senior Vice President Appalachia
Roger S. Manny	49	2003	Senior Vice President and Chief Financial Officer
Chad L. Stephens	51	1990	Senior Vice President Corporate Development
Rodney L. Waller	57	1999	Senior Vice President, Chief Compliance Officer and Corporate Secretary
Mark D. Whitley	55	2005	Senior Vice President Permian Business Unit and Engineering Technology

Charles L. Blackburn was elected as a director in 2003 and appointed as the non-executive Chairman of the Board. Mr. Blackburn has more than 40 years experience in oil and gas exploration and production serving in several executive and board positions. Previously, he served as Chairman and Chief Executive Officer of Maxus Energy Corporation from 1987 until that company s sale to YPF Socieded Anonima in 1995. Maxus was the oil and gas producer which remained after Diamond Shamrock Corporation s spin-off of its refining and marketing operations. Mr. Blackburn joined Diamond Shamrock in 1986 as President of their exploration and production subsidiary. From 1952 through 1986, Mr. Blackburn was with Shell Oil Company, serving as Director and Executive Vice President for exploration and production for the final ten years of that period. Mr. Blackburn has previously served on the Boards of Anderson Clayton and Co. (1978-1986), King Ranch Corp. (1987-1988), Penrod Drilling Co. (1988-1991), Landmark Graphics Corp. (1992-1996) and Lone Star Technologies, Inc. (1991-2001). Currently, Mr. Blackburn also serves as an advisory director to the oil and gas loan committee of Guaranty Bank. Mr. Blackburn received his Bachelor of Science degree in Engineering Physics from the University of Oklahoma in 1952.

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Prior to forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston (CSFB). Mr. Dub joined CSFB in 1971 and was named a Managing Director in 1981. Mr. Dub led a number of departments during his 26 year career at CSFB including the Investment Banking Department. After leaving CSFB, Mr. Dub became Vice Chairman and a director of Capital IQ, Inc. until its sale to Standard and Poor s in 2004. Capital IQ is the leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. Mr. Dub received a Bachelor of Arts, *magna cum laude*, from Princeton University.

V. Richard Eales became a director in 2001. Mr. Eales has over 35 years of experience in the energy, high technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources

Group Inc. from 1991 to 1999 serving as Executive Vice President from 1995 through 1999. Prior to 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation. Mr. Eales received his Bachelor of Chemical Engineering from Cornell University and his Masters in Business Administration from Stanford University.

Allen Finkelson became a director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore LLP since 1977, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn

Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore, LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of Range from 1998 to 2000. He has been active in the energy business since 1972. Mr. Linker joined First Reserve Corporation in 1988 and was a Managing Director of the firm from 1996 until July 2001. Mr. Linker is currently Manager of Houston Energy Advisors LLC, an investment advisor providing management and investment services to two private equity funds. Mr. Linker has been President and a director of IDC Energy Corporation since 1987, a director and officer of Sunset Production Corporation since 1991 serving currently as Chairman, and Manager of Shelby Resources Inc., all small, privately-owned exploration and production companies. Mr. Linker received a Bachelor of Arts in Geology from Amherst College, a Masters in Geology from Harvard University and an MBA from Harvard University s Graduate School of Business Administration.

Kevin S. McCarthy became a director in 2005. Mr. McCarthy is Chairman, Chief Executive Officer and President of Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc. and Kayne Anderson Energy Development Company which are each NYSE listed closed-end investment companies. Mr. McCarthy joined Kayne Anderson Capital Advisors as a Senior Managing Director in 2004 from UBS Securities LLC where he was global head of energy investment banking. In this role, he had senior responsibility for all of UBS energy investment banking activities, including direct responsibilities for securities underwriting and mergers and acquisitions in the energy industry. From 1995 to 2000, Mr. McCarthy led the energy investment banking activities of Dean Witter Reynolds and then PaineWebber Incorporated. He began his investment banking career in 1984. He is also on the board of directors of Clearwater Natural Resources, L.P. He earned a Bachelor of Arts in Economics and Geology from Amherst College and an MBA in Finance from the University of Pennsylvania s Wharton School.

John H. Pinkerton, President, Chief Executive Officer and a director, became a director in 1988. He joined Range as President in 1990 and was appointed Chief Executive Officer in 1992. Previously, Mr. Pinkerton was Senior Vice President of Snyder Oil Corporation (SOCO). Prior to joining SOCO in 1980, Mr. Pinkerton was with Arthur Andersen. Mr. Pinkerton received his Bachelor of Arts in Business Administration from Texas Christian University and a masters degree from the University of Texas at Arlington.

Jeffrey L. Ventura, Executive Vice President Chief Operating Officer, joined Range in 2003 and became a director in 2005. Previously, Mr. Ventura served as President and Chief Operating Officer of Matador Petroleum Corporation which he joined in 1997. Prior to 1997, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from Pennsylvania State University.

Alan W. Farquharson, Senior Vice President Reservoir Engineering, joined Range in 1998. Since joining Range, Mr. Farquharson has held the positions of Manager and Vice President of Reservoir Engineering. Previously, Mr. Farquharson held various positions with Union Pacific Resources including Engineering Manager Business Development International. Prior to that, Mr. Farquharson held various technical and managerial positions at Amoco and Hunt Oil. He holds a Bachelor of Science degree in Electrical Engineering from Pennsylvania State University.

Steven L. Grose, Senior Vice President Appalachia, joined Range in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. from 1971 until 1978. Mr. Grose is a member of the Society of Petroleum Engineers and is a past president of The Ohio Oil and Gas Association. Mr. Grose received his Bachelor of Science degree in Petroleum Engineering from Marietta College.

Roger S. Manny, Senior Vice President and Chief Financial Officer, joined Range in 2003. Previously, Mr. Manny served as Executive Vice President and Chief Financial Officer of Matador Petroleum Corporation since 1998. Prior to 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as Senior Vice President in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Chad L. Stephens, Senior Vice President Corporate Development, joined Range in 1990. Prior to 2002, Mr. Stephens held the position of Senior Vice President Southwest. Previously, Mr. Stephens was with Duer Wagner

& Co., an independent oil and gas producer for approximately two years. Prior to that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens received a Bachelor of Arts in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President and Corporate Secretary, joined Range in 1999. Since joining Range, Mr. Waller has held the position of Senior Vice President and Corporate Secretary. Previously, Mr. Waller was Senior Vice President of SOCO, now part of Devon Energy Corporation. Before joining SOCO, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller served as a director of Range from 1988 to 1994. Mr. Waller received a Bachelor of Arts degree in Accounting from Harding University.

Mark D. Whitley, Senior Vice President Permian Business Unit and Engineering Technology, joined Range in 2005. Previously, he served as Vice President Operations with Quicksilver Resources for two years. Prior to that, he

41

Table of Contents

served as Production/Operation Manager for Devon Energy, following the Devon/Mitchell merger. From 1982 to 2002, Mr. Whitley held a variety of technical and managerial roles with Mitchell Energy. Notably, he led the team of engineers at Mitchell Energy who applied new stimulation techniques to unlock the shale gas potential in the Fort Worth Basin. Previous positions included serving as a production and reservoir engineer with Shell Oil. He holds a Bachelor s degree in Chemical Engineering from Worcester Polytechnic Institute and a Master s degree in Chemical Engineering from the University of Kentucky.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading Section 16(a) Beneficial Ownership Reporting Compliance in the Range Proxy Statement for the 2007 Annual Meeting of stockholders which is incorporated herein by reference.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officers, principal financial officer, principal accounting officer, or persons performing similar functions. A copy is available on our website, www.rangeresources.com. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website at www.rangeresources.com, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Identifying and Evaluating Nominees for Directors

See the material under the heading Consideration of Director Nominees in the Range Proxy Statement for the 2007 Annual Meeting of stockholders which is incorporated herein by reference.

Audit Committee

See the material under the heading Audit Committee in the Range Proxy Statement for the 2007 Annual Meeting of stockholders which is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in our definitive Proxy Statement for the 2007 Annual Meeting of stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2007 Annual Meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2007 Annual Meeting of stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2007 Annual Meeting of stockholders.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report

1. Financial Statements:

2. All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

3. Exhibits:

(a) See Index of Exhibits on page F-37 for a description of the exhibits filed as a part of this report.

Table of Contents

GLOSSARY

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects the relative energy content.

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

dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field or to extend a known reservoir.

gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

infill well. A well drilled between known producing wells to better exploit the reservoir.

LIBOR. London Interbank Offer Rate, the rate of interest at which banks offer to lend to one another in the wholesale money markets in the City of London. This rate is a yardstick for lenders involved in many debt transactions.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million British thermal units. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Mmcf. One million cubic feet of gas.

Mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids.

net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

present value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.

productive well. A well that is producing oil or gas or that is capable of production.

proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Table of Contents

proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economics and operating conditions.

proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

recompletion. The completion for production an existing well bore in another formation from that in which the well has been previously completed.

reserve life index. Proved reserves at a point in time divided by the then production rate (annual or quarterly).

royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.
Dated: February 26, 2007

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton

John H. Pinkerton
President and Chief Executive Officer

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

/s/ Charles L. Blackburn	Chairman of the Board	February 26, 2007
Charles L. Blackburn		
/s/ John H. Pinkerton	President, Chief Executive Officer and Director	February 26, 2007
John H. Pinkerton		
/s/ Jeffrey L. Ventura	Executive Vice President and Director	February 26, 2007
Jeffrey L. Ventura		
/s/ Roger S. Manny	Chief Financial and Accounting Officer	February 26, 2007
Roger S. Manny		
/s/ Anthony V. Dub	Director	February 26, 2007
Anthony V. Dub		
/s/ V. Richard Eales	Director	February 26, 2007
V. Richard Eales		
/s/ Allen Finkelson	Director	February 26, 2007
Allen Finkelson		
/s/ Jonathan S. Linker	Director	February 26, 2007
Jonathan S. Linker		
/s/ Kevin S. McCarthy	Director	February 26, 2007

Kevin S. McCarthy

Table of Contents

RANGE RESOURCES CORPORATION
INDEX TO FINANCIAL STATEMENTS

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Range Resources Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2006, our internal control over financial reporting is effective based on those criteria.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, has been audited by Ernst & Young, LLP, an independent registered public accounting firm which also audited our consolidated financial statements. Ernst & Young s attestation report on management s assessment of our internal control over financial reporting is included under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting.

By:	/s/ John H. Pinkerton	By:	/s/ Roger S. Manny
	John H. Pinkerton		Roger S. Manny
	President and Chief Executive Officer		*Senior Vice President and Chief Financial Officer*

Fort Worth, Texas
February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Range Resources Corporation (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Range Resources Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Range Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Range Resources Corporation as of December 31, 2006 and 2005 and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2006 and our report dated February 26, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 26, 2007

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, in 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), Share-Based Payment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 26, 2007

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	December 31, 2006	2005
Assets		
Current assets:		
Cash and equivalents	$ 2,382	$ 4,750
Accounts receivable, less allowance for doubtful accounts of $746 and $624	130,349	128,532
Assets held for sale	79,304	
Unrealized derivative gain	93,588	425
Deferred tax asset		61,677
Inventory and other	14,714	12,593
Total current assets	320,337	207,977
Unrealized derivative gain	61,068	
Equity method investment	13,618	
Oil and gas properties, successful efforts method	3,641,227	2,548,090
Accumulated depletion and depreciation	(964,551)	(806,908)
	2,676,676	1,741,182
Transportation and field assets	80,066	65,210
Accumulated depreciation and amortization	(32,923)	(25,966)
	47,143	39,244
Other assets	68,832	30,582
Total assets	$ 3,187,674	$ 2,018,985
Liabilities		
Current liabilities:		
Accounts payable	$ 172,081	$ 119,907
Asset retirement obligations	4,216	3,166
Accrued liabilities	38,500	28,372
Accrued interest	12,938	10,214
Unrealized derivative loss	4,621	160,101
Total current liabilities	232,356	321,760
Bank debt	452,000	269,200
Subordinated notes	596,782	346,948
Deferred tax, net	468,643	174,817
Unrealized derivative loss	266	70,948

Deferred compensation liability	90,094	73,492
Asset retirement obligations	91,372	64,897
Commitments and contingencies		
Stockholders Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par, 250,000,000 shares authorized, 138,931,565 issued at December 31, 2006 and 129,913,046 issued at December 31, 2005	1,389	1,299
Common stock held in treasury 5,826 shares at December 31, 2005		(81)
Additional paid-in capital	1,079,994	845,519
Retained earnings	160,313	13,800
Common stock held by employee benefit trust, 1,853,279 and 1,971,605 shares, respectively, at cost	(22,056)	(11,852)
Deferred compensation		(4,635)
Accumulated other comprehensive income (loss)	36,521	(147,127)
Total stockholders equity	1,256,161	696,923
Total liabilities and stockholders equity	$ 3,187,674	$ 2,018,985

See accompanying notes.

F-5

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2006	**2005**	**2004**
Revenues			
Oil and gas sales	$ 683,928	$ 525,074	$ 315,703
Transportation and gathering	2,507	2,461	2,202
Mark-to-market on oil and gas derivatives	86,491	10,868	
Other	6,802	(2,563)	2,802
Total revenue	779,728	535,840	320,707
Costs and expenses			
Direct operating	92,224	67,112	46,308
Production and ad valorem taxes	36,915	31,516	20,504
Exploration	45,252	30,604	21,219
General and administrative	49,886	33,444	20,634
Deferred compensation plan	6,873	29,474	19,176
Interest expense	57,577	38,797	23,119
Depletion, depreciation and amortization	169,661	127,514	102,971
Total costs and expenses	458,388	358,461	253,931
Income from continuing operations before income taxes	321,340	177,379	66,776
Income tax provision (benefit)			
Current	1,912	1,071	(245)
Deferred	121,814	65,297	24,790
	123,726	66,368	24,545
Income from continuing operations	197,614	111,011	42,231
Discontinued operations, net of taxes	(38,912)		
Net income	158,702	111,011	42,231
Preferred dividends			(5,163)
Net income available to common stockholders	$ 158,702	$ 111,011	$ 37,068
Earnings per common share:			
Basic income from continuing operations	$ 1.48	$ 0.89	$ 0.40

discontinued operations			(0.29)				
net income		$	1.19	$	0.89	$	0.40
Diluted	income from continuing operations	$	1.42	$	0.86	$	0.38
discontinued operations			(0.28)				
net income		$	1.14	$	0.86	$	0.38

See accompanying notes.

F-6

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2006	2005	2004
Operating activities:			
Net income	$ 158,702	$ 111,011	$ 42,231
Adjustments to reconcile net cash provided from operating activities:			
Loss from discontinued operations	38,912		
Gain from equity method investment	(548)		
Deferred income tax expense	121,814	65,297	24,790
Depletion, depreciation and amortization	169,661	127,514	102,971
Exploration dry hole costs	16,103	7,045	9,493
Mark-to-market on oil and gas derivatives gains	(86,491)	(10,868)	
Unrealized derivative (gains) losses	(5,654)	3,505	(1,793)
Allowance for bad debts	80	675	1,762
Amortization of deferred financing costs and discount	1,827	1,662	1,071
Non-cash compensation	27,455	37,391	20,667
(Gain) loss on sale of assets and other	940	(512)	(3,109)
Changes in working capital, net of amounts from business acquisitions:			
Accounts receivable	32,881	(44,533)	(25,898)
Inventory and other	(1,157)	(3,452)	(6,080)
Accounts payable	(5,049)	27,472	34,746
Accrued liabilities and other	(1,861)	3,538	8,398
Net cash provided from continuing operations	467,615	325,745	209,249
Net cash provided from discontinued operations	12,260		
Net cash provided from operating activities	479,875	325,745	209,249
Investing activities:			
Additions to oil and gas properties	(502,944)	(276,907)	(166,560)
Additions to field service assets	(14,449)	(11,310)	(4,237)
Acquisitions, net of cash acquired	(360,149)	(153,600)	(485,564)
Investing activities of discontinued operations	(13,496)		
Investment in equity method affiliate and other assets	(21,009)		
Proceeds from disposal of assets and other repayments	388	9,440	32,060
Net cash used in investing activities	(911,659)	(432,377)	(624,301)
Financing activities:			
Borrowings on credit facilities	802,500	299,000	634,578
Repayments on credit facilities	(619,700)	(453,700)	(528,878)
Issuance of subordinated notes	249,500	150,000	98,125

Treasury stock purchases		(2,808)	
Dividends paid common stock	(12,189)	(7,614)	(3,219)
preferred stock		(2,213)	(2,950)
Debt issuance costs	(6,960)	(4,119)	(3,630)
Issuance of common stock	16,265	114,470	250,460
Other debt repayments		(16)	(11,683)
Net cash provided from financing activities	429,416	93,000	432,803
Net increase (decrease) in cash and equivalents	(2,368)	(13,632)	17,751
Cash and equivalents at beginning of year	4,750	18,382	631
Cash and equivalents at end of year	$ 2,382	$ 4,750	$ 18,382

See accompanying notes.

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Preferred stock		Common stock		Treasury	Additional	Retained	Stock held by employee benefit	Deferred	Accumulated other comprehensive	
	Shares	Par Value	Shares	Par Value	common stock	paid-in capital	earnings (deficit)	trust	compensation	(loss)/gain	Total
lance ecember 31, 03	1,000	$ 50,000	84,616	$ 846	$	$ 399,380	$ (124,011)	$ (8,441)	$ (856)	$ (42,852)	**$ 274,06**
eferred vidends 5.16 per are)							(5,163)				**(5,16**
suance of mmon stock			28,390	284		258,171		255	(401)		**258,30**
ommon vidends 0.0267 per are)							(2,654)				**(2,65**
onversion of curities	(1,000)	(50,000)	8,823	88		49,912					
her mprehensive ss										(449)	**(44**
t income							42,231				**42,23**
lance ecember 31, 04			121,829	1,218		707,463	(89,597)	(8,186)	(1,257)	(43,301)	**566,34**
suance of mmon stock			8,084	81		138,056		(3,666)	(3,378)		**131,09**
ommon vidends 0.0599 per are)							(7,614)				**(7,61**

easury stock rchases			(2,808)						**(2,80**
easury stock uances			2,727						**2,72**
her mprehensive ss								(103,826)	**(103,82**
et income					111,011				**111,01**
alance ecember 31, 05	129,913	1,299	(81)	845,519	13,800	(11,852)	(4,635)	(147,127)	**696,92**
suance of mmon stock	9,018	90		234,475		(10,204)	4,635		**228,99**
ommon vidends 0.09 per are)					(12,189)				**(12,18**
easury stock uances			81						**8**
her mprehensive in								183,648	**183,64**
et income					158,702				**158,70**
alance ecember 31, 06	**$ 138,931**	**$ 1,389**	**$**	**$ 1,079,994**	**$ 160,313**	**$ (22,056)**	**$**	**$ 36,521**	**$ 1,256,16**

See accompanying notes.

F-8

Table of Contents

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2006	**2005**	**2004**
Net income	$ 158,702	$ 111,011	$ 42,231
Net deferred hedging gains (losses), net of tax:			
Contract settlements reclassified to income	29,302	101,209	63,633
Change in unrealized deferred hedging gains (losses)	152,294	(206,348)	(64,477)
Change in unrealized gains on securities held by deferred compensation plan, net of taxes	2,052	1,313	395
Comprehensive income	$ 342,350	$ 7,185	$ 41,782

See accompanying notes

F-9

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (Range, we, us, or our) is engaged in the exploration, development and acquisitio of oil and gas properties primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Prior to June 2004, we held our Appalachian oil and gas assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. or Great Lakes. In June 2004, we purchased the 50% of Great Lakes that we did not own. Range is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. The statement of operations for the year ended December 31, 2004 includes 50% of the revenues and expenses of Great Lakes up to June 23, 2004 and 100% thereafter. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in other revenues on our consolidated statement of operations. All material intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Actual results could differ from the estimates and assumptions used.

Income per Common Share

Basic net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net income per share assumes issuance of stock compensation awards and conversion of convertible debt and preferred securities, provided the effect is not antidilutive. All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the three-for-two stock split effected on December 2, 2005.

Business Segment Information

The Financial Accounting Standards Board (FASB), Statement of Financial Accounting Standards (SFAS) No. 131, Disclosure About Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable to us as 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. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. Although receivables are concentrated in the oil and gas industry, we do not view this as unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. We have allowances for doubtful accounts relating to exploration and production receivables of $745,900 at December 31, 2006 compared to $623,800 at December 31, 2005.

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at December 31, 2006 and December 31, 2005 were not significant. At December 31, 2006, we had recorded a net liability of $441,200 for those wells where it was determined that there was insufficient reserves to recover the imbalance situation.

Cash and Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Marketable Securities

Holdings of equity securities qualify as available-for-sale or trading and are recorded at fair value.

Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of specific cost of each inventory item or market value.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Oil and NGLs are converted to gas equivalent basis or mcfe at the rate one barrel equals 6 mcf. The depletion, depreciation and amortization (DD&A) rates were $1.68 per mcfe in 2006 compared to $1.46 per mcfe in 2005 and $1.44 per mcfe in 2004. Depletion is provided on the units of production method. Unproved properties had a net book value of $226.3 million at December 31, 2006 compared to $28.6 million at December 31, 2005 and $14.8 million at December 31, 2004. The increase in unproved properties in 2006 is primarily related to our Stroud acquisition completed in 2006. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not explore the acreage prior to expiration or the carrying value is above fair value.

Our long-lived assets are reviewed for impairment periodically for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop proved reserves. Expected future cash inflow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value, (as determined by discounted future net cash flows) and the carrying value of the asset. In the third quarter of 2006, we recorded in

DD&A a $2.4 million impairment on an offshore property due to declining oil and gas prices. 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.

Proceeds from the disposal of miscellaneous properties are credited to the net book value of their amortization group with no immediate effect on income. However, gain or loss is recognized from the sale of less than an entire amortization group if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing certain transportation and field services which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense was $7.5 million in 2006 compared to $6.4 million in 2005 and $4.7 million in 2004.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are amortized over the expected life of the related instruments. When an instrument is retired prior to maturity or modifications significantly change the cash flows, related unamortized costs are expensed. Other assets at December 31, 2006 include $13.4 million of unamortized debt issuance costs, $44.2 million of marketable securities held in our deferred compensation plans and $9.0 million of other investments.

Stock-based Compensation

The 2005 Equity Based Compensation Plan (the 2005 Plan) authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, restricted stock awards, and phantom stock rights to employees. The Non-Employee Director Stock Plan (the Director Plan) allows grants to our non-employee directors of our Board of Directors. The 2005 Plan was approved by shareholders in May 2005 and replaces our 1999 stock option plan. No new grants will be made from the 1999 stock option plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Options Plan prior to May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005, that subsequently lapse or terminate without the underlying shares being issued. The Director Plan was approved by shareholders in May 2004 and no more than 300,000 shares of common stock may be issued under the Plan.

Stock options represent the right to purchase shares of stock in the future at the fair market value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three year period and expire five years from the date they are granted. Similar to stock options, stock appreciation rights (SARs), represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three year period and have a maximum term of five years from the date they are granted. We began issuing SARs in 2005 instead of options to reduce the dilution impact of our equity compensation plans.

The Compensation Committee grants restricted stock to certain employees and to non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period.

Prior to January 1, 2006, we accounted for stock options granted under our stock-based compensation plans under the recognition and measurement provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees and related Interpretations, as permitted by SFAS No. 123, Accounting for Stock-Based Compensation. For our stock options, no stock-based compensation expense was recognized in our statements of operations prior to January 1, 2006, as all stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), Share-Based Payment, using the modified prospective transition method. Under this transition method, compensation cost for stock options and stock appreciation rights recognized in 2006 includes (a) compensation cost ($11.2 million) for all stock-based payments granted prior to, but not yet vested as of December 31, 2005, based on the remaining service period and the grant date fair value estimated in accordance with the original provisions of Statement No. 123 and (b) compensation cost ($3.7 million) for all stock-based payments granted subsequent to December 31, 2005, based on the service period (on a straight line basis) and the grant-date fair value estimated in accordance with SFAS No. 123(R). Pursuant to SFAS No. 123(R), results for prior periods have not been restated. In 2006, stock based compensation has been allocated to direct operating expense ($1.4 million), exploration expense ($2.5 million), general and administrative expense ($10.7 million) and a $303,000 reduction to transportation and gathering revenues to align SFAS No. 123(R) expense with the employee s cash compensation.

We also began granting stock-settled SARs in July 2005 as part of our stock-based compensation plans to reduce the dilutive impact of our equity plans. Prior to January 1, 2006, we accounted for these SARs grants under the recognition and measurement provisions of APB Opinion No. 25, which required expense to be recognized equal to the amount by which the quoted market value exceeded the original grant price on a mark-to-market basis. Therefore, we recognized $5.8 million of compensation cost in the last six months of 2005 related to SARs. In order to present stock-based compensation expense on a consistent basis, the $5.8 million of 2005 SARs related expense has been allocated to direct operating expense ($480,000), exploration expense ($1.2 million), general and administrative expense ($4.0 million) and a $117,000 reduction to transportation and gathering revenues. Beginning January 1, 2006, as required under the provisions of SFAS No. 123(R), those SARs granted prior to, but not yet vested as of December 31, 2005, are being expensed over the service period based on grant date fair value estimated in accordance with the original provisions of SFAS No. 123 and all SARs granted subsequent to December 31, 2005 are being expensed over the service period on a straight line basis based on grant-date fair value estimated in accordance with SFAS No. 123(R).

As a result of adopting SFAS No. 123(R) on January 1, 2006, our income from continuing operations before income taxes and net income for 2006 is $18.2 million and $11.5 million lower, respectively, than if we had continued to account for stock-based compensation under APB Opinion No. 25. Also, as a result of adopting SFAS No. 123(R), our December 31, 2005 unearned deferred compensation and additional paid-in capital related to our restricted stock issuances was eliminated. As of December 31, 2006, there was $12.4 million of unrecognized compensation related to restricted stock awards expected to be recognized over the next 3 years.

The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS No. 123(R) to options and SARs granted under our stock-based compensation plans in 2005 and 2004. For the purposes of this pro forma disclosure, the value is estimated using a Black-Scholes-Merton option-pricing formula and expensed over the option s vesting periods.

	Year Ended December 31, 2005	2004
	(in thousands, except per share data)	
Net income as reported	$ 111,011	$ 42,231
Add: Total stock-based employee compensation expense included in net income, net of tax	23,556	13,020
Deduct: Total stock-based employee compensation expense determined under fair value based method, net of tax	(29,235)	(17,114)
Pro forma net income	$ 105,332	$ 38,137
Earnings per share:		
Basic as reported	$ 0.89	$ 0.40
Basic pro forma	0.85	0.35
Diluted as reported	0.86	0.38
Diluted pro forma	0.82	0.34

As required, the pro forma disclosures above included options and SARs granted since January 1, 1995. For purposes of pro forma disclosures, the estimated fair value is amortized to expense over the vesting period. For options with graded vesting, expense is recognized on a straight-line basis over the vesting period. The fair value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes option pricing model with the following weighted-average assumptions used for 2005 and 2004: fair value of $8.48 and $4.52 per share;

expected dividend per share of $0.08 and $0.04; expected historical volatility factors of 54% and 67%; risk-free interest rates of 4.1% and 3.5%, and an average expected life of 5 years.

Derivative Financial Instruments and Hedging

We use commodity-based derivatives to reduce the volatility of oil and gas prices. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in a component of stockholders equity called other comprehensive income (OCI), and then reclassified to income, as a component of oil and gas revenues, when the underlying anticipated transaction occurs. Any ineffective portion (changes in realized prices that do not match changes in the reference price used to settle the hedge) is recognized in earnings, as a component of other revenues, as it occurs. Ineffective gains or losses are recorded while the hedge contract is open and may increase or reverse until settlement of the contract. Typically, when oil and gas prices increase, OCI decreases. Of the $149.8 million gain recorded in OCI at December 31, 2006, $89.0 million is expected to be reclassified to income in 2007, if prices remain at their December 31, 2006 levels. Actual amounts that will be reclassified will vary as a result of changes in prices. As of the fourth quarter of 2005, certain of our oil and gas derivatives no longer qualify for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices. As a result, we recognized a gain of $10.9 million in the fourth quarter of 2005 and a gain of $86.5 million in the year ended December 31, 2006 related to these oil and gas derivatives that no longer qualify for hedge accounting. We expect these derivative positions will continue to be marked to market going forward. This may result in more volatility in our income in future periods.

Asset Retirement Obligations

The fair values of asset retirement obligations are recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. The depreciation will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. We do not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income including tax credits and operating loss carryforwards.

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS No. 130, Reporting Comprehensive Income which establishes standards for reporting comprehensive income. Comprehensive income includes net income as well as all changes in equity during the period, except those resulting from investments and distributions to owners. At December 31, 2006, we had a $51.3 million pre-tax gain in OCI relating to unrealized commodity hedges. We also had a pre-tax gain of $6.2 million relating to our marketable securities held in the deferred compensation plan.

The components of accumulated other comprehensive income (loss) and related tax effects for three years ended December 31, 2006, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2003	$ (67,472)	$ 24,620	$ (42,852)
Contract settlements reclassified to income	100,121	(36,488)	63,633
Change in unrealized deferred hedging losses	(102,506)	38,029	(64,477)
Change in unrealized gains (losses) on securities held by deferred compensation plan	626	(231)	395
Accumulated other comprehensive loss at December 31, 2004	(69,231)	25,930	(43,301)
Contract settlements reclassified to income	160,267	(59,058)	101,209
Change in unrealized deferred hedging losses	(327,448)	121,100	(206,348)
	2,049	(736)	1,313

Change in unrealized gains (losses) on securities held by deferred compensation plan			
Accumulated other comprehensive loss at December 31, 2005	(234,363)	87,236	(147,127)
Contract settlements reclassified to income	46,511	(17,209)	29,302
Change in unrealized deferred hedging gains	242,122	(89,828)	152,294
Change in unrealized gains (losses) on securities held by deferred compensation plan	3,203	(1,151)	2,052
Accumulated other comprehensive income at December 31, 2006	$ 57,473	$ (20,952)	$ 36,521

Table of Contents

Reclassifications

Certain reclassifications of prior years data have been made to conform with our current year classification. This includes a reclassification in 2005 of our SARs mark-to-market expense of $5.8 million from deferred compensation plan expense to direct operating expense ($480,000), exploration expense ($1.2 million), general and administrative expense ($4.0 million) and a $117,000 reduction of gas transportation revenues. This reclassification was made to align the expense with employee cash compensation. These reclassifications did not impact our net income, stockholders equity or cash flows.

Accounting Pronouncements Implemented

In December 2004, the FASB issued SFAS No. 123(R) as a revision of SFAS No. 123, Accounting for Stock-Based Compensation. This statement requires entities to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the grant date. That cost is recognized over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. In addition, awards classified as liabilities are remeasured at fair value each reporting period.

We adopted SFAS No. 123(R) as of January 1, 2006, for all awards granted, modified or cancelled after adoption, and for the unvested portion of awards outstanding at January 1, 2006. At the date of adoption, SFAS No. 123(R) requires that an assumed forfeiture rate be applied to any unvested awards and that awards classified as liabilities be measured at fair value. Prior to adopting SFAS No. 123(R), we recognized forfeitures as they occurred and applied the intrinsic value method to awards classified as liabilities.

SFAS No. 123(R) also requires a company to calculate the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to adopting the statement. In November 2005, the FASB issued FASB Staff Position No. 123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, to provide an alternative transition election (the short-cut method) to account for the tax effects of share-based payment awards to employees. We elected the short-cut method to determine our pool of excess tax benefits as of January 1, 2006.

See Stock-based compensation above and Note 12 to the consolidated financial statements for the disclosures regarding share-based payments required by SFAS No. 123(R).

Effective January 1, 2006, we adopted SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires companies to recognize (1) voluntary changes in accounting principle and (2) changes required by a new accounting pronouncement, when the pronouncement does not include specific transition provisions, retrospectively to prior periods financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The adoption had no immediate effect on our financial statements.

In September 2006, the SEC issued SEC Staff Accounting Bulletin (SAB) No. 108, Financial Statements Considering the Effects of Prior-Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 addresses how a registrant should quantify the effect of an error in the financial statements for purposes of assessing materiality and requires that the effect be computed using both the current year income statement perspective (rollover) and the year-end balance sheet perspective (iron curtain) methods for fiscal years ending after November 15, 2006. If a change in the method of quantifying errors is required under SAB No. 108, this represents a change in accounting policy; therefore, if the use of both methods results in a larger, material misstatement than the previously applied method, the financial statements must be adjusted. SAB No. 108 allows the cumulative effect of such adjustments to be made to opening retained earnings upon adoption. The adoption of SAB No. 108 did not have a significant effect on our consolidated results of operations, financial position or cash flows.

Accounting Pronouncements Not Yet Adopted

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Range, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In July 2006, the FASB issued FASB Interpretation (FIN) 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN 48 clarifies the accounting for uncertain income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. The cumulative effect of adoption FIN 48 will be recorded in retained earnings. For Range, the provisions of FIN 48 are effective January 1, 2007. We are currently evaluating the provisions of FIN 48 to determine the impact on our consolidated financial statements but we do not expect a material impact on our financial position or results of operations.

In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). Included in the scope of this issue are any taxes assessed by a governmental authority that are imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF concluded that the presentation of such taxes on a gross basis (included in revenues and costs) or a net basis (excluded from revenues) is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22. In addition, the amounts of such taxes reported on a gross basis must be disclosed if those tax amounts are significant. For Range, the disclosure prescribed by this consensus is required in our 2007 consolidated financial statements but early application is permitted.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our statement of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. We purchased various properties for consideration of $709.0 million in 2006 compared to $173.5 million in 2005 and $648.2 million in 2004. These purchases included $630.1 million, $152.8 million and $619.0 million for proved oil and gas reserves, respectively; the remainder represents unproved acreage purchases. As part of our acquisitions for 2006, we allocated $140.0 million to the Austin Chalk properties which were classified as Assets Held for Sale at December 31, 2006. As part of our acquisitions for 2004, we allocated $15.5 million to gathering facilities acquired in the transactions. See also Note 19 Costs Incurred for Property Acquisition, Exploration and Development.

Our purchases in 2006 include the acquisition in June of Stroud Energy, Inc. (Stroud), a private oil and gas company with operations in the Barnett Shale in North Texas, the Cotton Valley in East Texas and the Austin Chalk in Central Texas. To acquire Stroud, we paid $171.5 million of cash (including transaction costs) and issued 6.5 million shares of our common stock. The cash portion of the acquisition was funded with borrowings under our bank facility. We also assumed $106.7 million of Stroud s debt which was retired with borrowings under our bank facility. The fair value of consideration issued was based on the average of our stock price for the five day period before and after May 11, 2006, the date the acquisition was announced. See also Note 4 for discussion of assets held for sale.

The following table summarizes the final purchase price allocation of fair values of assets acquired and liabilities assumed at closing (in thousands):

Purchase price:		
Cash paid (including transaction costs)	$	171,529
6.5 million shares of common stock (at fair value of $27.26 per share)		177,641
Stock options assumed (652,000 options)		9,478
Debt retired		106,700
Total	$	465,348
Allocation of purchase price:		
Working capital deficit	$	(13,557)
Other long-term assets		55
Oil and gas properties		487,345
Assets held for sale		140,000
Deferred income taxes		(147,062)

Asset retirement obligations		(1,433)
Total	$	465,348

Table of Contents

The following unaudited pro forma data include the results of operations as if the Stroud acquisition had been consummated at the beginning of 2005. The pro forma information for 2005 includes two material non-recurring amounts not directly related to the transaction and not expected to reoccur. The year ended December 31, 2005 pro forma information includes an $18.4 million pre-tax stock compensation expense related to restricted and unrestricted shares issued to Stroud management and employees and a pre-tax $6.2 million loss on repurchase of mandatorily redeemable preferred units. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Year Ended December 31,	
	2006	2005
Revenues	$814,548	$553,345
Income from continuing operations	$320,859	$133,433
Net income	$161,998	$ 95,066
Per share data:		
Income from continuing operations-basic	$ 1.44	$ 0.63
Income from continuing operations-diluted	$ 1.39	$ 0.61
Net income basic	$ 1.18	$ 0.73
Net income diluted	$ 1.14	$ 0.70

In 2004, we purchased Appalachian oil and gas properties, through the purchase of Pine Mountain, for $152.4 million cash paid to the seller, $57.2 million cash paid to repay debt and $13.3 million for the retirement of oil and gas commodity hedges. Also in 2004, we purchased the 50% of Great Lakes we did not previously own for $200.0 million cash paid to the seller plus the assumption of $70.0 million of Great Lakes bank debt and the retirement of $27.7 million of oil and gas commodity hedges. The debt assumed was refinanced and consolidated with our existing credit facility as of the purchase date.

The following unaudited pro forma data include the results of operations of the Pine Mountain and Great Lakes acquisitions as if they had been consummated at the beginning of 2004. The pro forma data are based on historical information and do not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share amounts).

	2004
Revenues	$377,564
Income before income taxes	84,484
Net income	53,385
Earnings per common share:	
Basic	$ 0.44
Diluted	$ 0.42

Table of Contents

(4) ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

As part of the Stroud acquisition (see discussion in Note 3), we purchased Austin Chalk properties in Central Texas which were sold in February 2007 for proceeds of $80.4 million. We originally allocated $140.0 million to these properties. However, subsequent to the acquisition natural gas prices started to decline. As a result, we recognized impairment of $74.9 million, and at December 31, 2006 the carrying value is equal to sales proceeds less costs to sell. See also Note 17. We believe we have met the criteria of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets that allow us to classify these assets as held for sale on our balance sheet and have presented the results of operations (revenues less direct expenses, interest, impairment and taxes) as discontinued operations in all future periods. Discontinued operations for the year ended December 31, 2006 are summarized as follows (in thousands):

	June 19, 2006 through December 31, 2006
Revenues	$ 19,342
Less:	
Direct operating, production and ad valorem taxes	1,803
General, administrative and exploration expense	1,236
Interest expense [1]	1,504
Impairment and accretion expense [2]	74,941
Loss before income taxes	(60,142)
Income tax benefit	21,230
Net loss from discontinued operations	$ (38,912)
Average daily production:	
Crude oil (bbls)	96
Natural gas (mcf)	17,300
Total (per mcfe)	17,876

(1) Interest expense is allocated to discontinued operations based on our ratio of consolidated debt to equity at the time of the acquisition.

(2) Impairment expense includes losses in fair value resulting from

lower oil and gas prices and volumes produced since the acquisition date.

(5) INCOME TAXES

Our income tax expense from continuing operations was $123.7 million for the year ended December 31, 2006 compared to $66.4 million in 2005 and $24.5 million in 2004. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2006	2005	2004
Federal statutory tax rate	35%	35%	35%
State	4	2	2
Consolidated effective tax rate	39%	37%	37%
Income taxes paid (in thousands)	$ 1,973	$ 615	$ 150

Table of Contents

Income tax provision (benefit) attributable to income from continuing operations consists of the following:

	Year Ended December 31, 2006	2005	2004
	(in thousands)		
Current:			
U.S. federal	$ 150	$	$ (192)
U.S. state and local	1,762	1,071	(53)
	$ 1,912	$ 1,071	$ (245)
Deferred:			
U.S. federal	$ 112,270	$ 61,767	$ 23,450
U.S. state and local	9,544	3,530	1,340
	$ 121,814	$ 65,297	$ 24,790

Significant components of deferred tax assets and liabilities are as follows:

	December 31, 2006	2005
	(in thousands)	
Deferred tax assets		
Net operating loss carryover	$ 69,141	$ 76,944
Allowance for doubtful accounts	962	1,166
Net unrealized loss in OCI		85,462
Deferred compensation	38,664	27,721
AMT credits and other	30,641	44,738
Total deferred tax assets	139,408	236,031
Deferred tax liabilities		
Depreciation and depletion	(547,899)	(346,070)
Net unrealized gain in OCI	(21,264)	
Valuation allowance and other	(38,888)	(3,101)
Total deferred tax liabilities	(608,051)	(349,171)
Net deferred tax liability	$ (468,643)	$ (113,140)

At December 31, 2006, deferred tax liabilities exceeded deferred tax assets by $468.6 million, with $21.3 million of deferred tax liabilities related to net deferred hedging gains included in OCI. A portion of our deferred tax assets relate to items which are capital assets, which upon disposition will result in capital losses. Due to the uncertainty related to the utilization of the capital loss, a valuation allowance was recognized in the amount of $3.1 million.

At December 31, 2006, we had regular net operating loss (NOL) carryovers of $229.6 million and alternative minimum tax (AMT) NOL carryovers of $192.4 million that expire between 2012 and 2026. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. We have $26.9 million of NOLs generated in years prior to 1998 which are subject to yearly limitations due to IRC Section 382. We do not believe the application of the Section 382 limitation hinders our ability to utilize such NOLs and therefore, no valuation allowance has been provided. At December 31, 2006, we have AMT credit carryovers of $700,000 that are not subject to limitation or expiration.

Table of Contents

(6) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands, except per share amounts):

	Year Ended December 31, 2006	2005	2004
Numerator:			
Income from continuing operations	$ 197,614	$ 111,011	$ 42,231
Loss from discontinued operations	(38,912)		
Preferred stock dividends			(5,163)
Net income	$ 158,702	$ 111,011	$ 37,068
Denominator:			
Weighted average shares outstanding	135,016	126,339	96,050
Stock held in deferred compensation plan and treasury shares	(1,265)	(2,209)	(2,506)
Weighted average shares, basic	133,751	124,130	93,544
Effect of dilutive securities:			
Weighted average shares outstanding	135,016	126,339	96,050
Employee stock options and other	3,696	2,863	1,948
Treasury shares	(1)	(76)	
Dilutive potential common shares for diluted earnings per share	138,711	129,126	97,998
Basic income from continuing operations	$ 1.48	$ 0.89	$ 0.40
discontinued operations	(0.29)		
net income	$ $1.19	$ 0.89	$ 0.40
Diluted income from continuing operations	$ 1.42	$ 0.86	$ 0.38
discontinued operations	(0.28)		
net income	$ 1.14	$ 0.86	$ 0.38

Stock appreciation rights for 88,500 shares were outstanding but not included in the computations of diluted net income per share for the year ended December 31, 2006 because the exercise price of the SARs was greater than the average price of the common shares and would be anti-dilutive to the computations. Options to purchase 318,200 shares of common stock were outstanding but not included in the computation of diluted net income per shares for the year ended December 31, 2004 because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations.

Table of Contents

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2006, 2005 and 2004 (in thousands):

	2006	2005	2004
Balance at beginning of period	$ 25,340	$ 7,332	$ 2,043
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,695	26,915	4,767
Additions due to purchase of Great Lakes			2,012
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(16,710)	(8,614)	(784)
Capitalized exploratory well costs charged to expense	(3,341)	(293)	(706)
Balance at end of period	9,984	25,340	7,332
Less exploratory well costs that have been capitalized for a period of one year or less	(4,792)	(21,589)	(6,124)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 5,192	$ 3,751	$ 1,208
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	3

As of December 31, 2006, of the $5.2 million of capitalized exploratory well costs that have been capitalized for more than one year, all of the wells have additional exploratory wells in the same prospect area drilling or firmly planned. None of the wells are operated by us. The $10.0 million of capitalized exploratory well costs at December 31, 2006 was incurred in 2006 ($4.7 million), in 2005 ($2.9 million) and in 2004 ($2.4 million).

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2006 is shown parenthetically). No interest was capitalized during 2006, 2005, and 2004 (in thousands):

	December 31,	
	2006	2005
Bank debt (6.4%)	$ 452,000	$ 269,200
Senior Subordinated Notes:		
7.375% Senior Subordinated Notes due 2013, net of $2.7 million and $3.1 million discount, respectively	197,262	196,948
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of $480,000 discount	249,520	
Total debt	$ 1,048,782	$ 616,148

Bank Debt

In October 2006, we entered into an amended and restated $800.0 million revolving bank credit facility, which we refer to as our bank debt or bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of an $800.0 million facility amount or the borrowing base. The borrowing base as of February 22, 2007 was $1.2 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. The facility amount may be increased to the borrowing base amount with twenty days notice. As of December 31, 2006, the outstanding balance under the bank credit facility was $452.0 million and there was $348.0 million of borrowing capacity available. The loan matures on October 25, 2011. Borrowing under the bank credit facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the weekly ceiling as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the Maximum Rate) or, (ii) the sum of (A) the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such date plus one-half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.5% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. We may elect, from time-to-time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 6.4% and 4.5% for the years ended December 31, 2006 and 2005, respectively. A commitment fee is paid on the undrawn balance based on an annual rate of 0.25% to 0.375%. At December, 31, 2006, the commitment fee was 0.25% and the interest rate margin was 1.0%. At February 22, 2007, the interest rate (including applicable margin) was 6.4%.

Senior Subordinated Notes

In 2003, we issued $100.0 million aggregate principal amount of 7.375% senior subordinated notes due 2013 (7.375% Notes). In 2004, we issued an additional $100.0 million of 7.375% Notes; therefore, $200.0 million of the 7.375% Notes are currently outstanding. The 7.375% Notes were issued at a discount which will be amortized over the life of the 7.375% Notes into interest expense. In 2005, we issued $150.0 million of 6.375% senior subordinated notes due 2015 (6.375% Notes). In May 2006, we issued $150.0 million of the 7.5% Senior Subordinated Notes due 2016 (the 7.5% Notes). In August 2006, we issued an additional $100.0 million of the 7.5% Notes; therefore, $250.0 million of the 7.5% Notes are currently outstanding. Interest on our senior subordinated notes is payable semi-annually and each of the notes are guaranteed by certain of our subsidiaries.

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. Prior to July 15, 2006, we may redeem up to 35% of the original aggregate principal amount of the 7.375% Notes at a redemption price of 107.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 6.375% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.2% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. Prior to March 15, 2008, we may redeem up to 35% of the original aggregate principal amount of the 6.375% Notes at a redemption price of 106.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 7.5% Notes, in whole or in part, at any time on or after May 15, 2011 at redemption prices from 103.75% of the principal amount as of May 15, 2011 and declining to 100% on May 15, 2014 and thereafter. Prior to May 15, 2009, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest if any, with the proceeds of certain equity offerings; provided that at least 65% of the original aggregate principal amount of our 7.5% Notes remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale.

If we experience a change of control, there may be a requirement to repurchase all or a portion of the senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees of the 7.375% Notes, the 6.375% Notes and the 7.5% Notes are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are minor subsidiaries.

Table of Contents

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2006. Under the bank credit facility, common and preferred dividends are permitted, subject to the provisions of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances. Approximately $446.4 million was available under the bank credit facility s restricted payment basket on December 31, 2006. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. At December 31, 2006, approximately $496.2 million was available under the restricted payment baskets for each of the subordinated notes.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2006 (in thousands):

	Year Ended December 31:
2007	$
2008	
2009	
2010	
2011	452,000
2012	
Thereafter	600,000
	$ 1,052,000

(9) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2006 and 2005 is as follows (in thousands):

	2006	2005
Beginning of period	$ 68,063	$ 70,727
Liabilities incurred	4,006	3,694
Acquisitions continuing operations	790	119
Acquisitions discontinued operations	742	
Liabilities settled	(3,057)	(6,126)
Accretion expense continuing operations	4,824	5,072
Accretion expense discontinued operations	37	
Change in estimate	20,183	(5,423)
End of period	95,588	68,063
Less current portion	(4,216)	(3,166)
Long-term portion	$ 91,372	$ 64,897

Accretion expense is recognized as a component of depreciation, depletion and amortization. The significant increase in 2006 as a result of changes in estimates is primarily related to rising abandonment costs and lower gas prices which accelerated the timing of abandonment.

Table of Contents

(10) CAPITAL STOCK

We have authorized capital stock of 260 million shares which includes 250 million shares of common stock and 10 million shares of preferred stock. All shares have been adjusted for the three-for-two common stock split affected on December 2, 2005. All common stock shares and treasury shares have been retroactively restated to reflect this stock split.

The following is a schedule of changes in the number of outstanding common shares since the beginning of 2005:

	Year Ended December 31,	
	2006	2005
Beginning balance	129,907,220	121,829,027
Public offerings		6,900,000
Shares issued for Stroud acquisition	6,517,498	
Shares issued in lieu of bonuses	20,686	25,590
Stock options/SARs exercised	1,956,164	1,105,549
Restricted stock grants	474,609	
Deferred compensation plan	12,998	20,885
Shares contributed to 401(k) plan	36,564	33,018
Fractional shares		(1,023)
Treasury shares	5,826	(5,826)
Ending balance	138,931,565	129,907,220

In June 2005, we completed a public offering of 6.9 million shares of common stock at $16.51 per share. Net proceeds from the offering of $109.2 million funded our acquisition of certain Permian basin properties.

Treasury Stock

During 2005, we bought in open market purchases, 201,000 shares at an average price of $14.00. As of December 31, 2006, all of these shares had been used for equity compensation. The board of directors has approved up to an additional $10.0 million of repurchases of common stock based on market conditions and opportunities.

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Financial instruments include cash and equivalents, receivables, payables, marketable securities, debt and commodity and interest rate derivatives. The carrying value of cash and equivalents, receivables, payables is considered to be representative of fair value because of their short maturity.

Table of Contents

The following table sets forth our other financial instruments fair values at each of these dates (in thousands):

	December 31, 2006		December 31, 2005	
	Book Value	Fair Value	Book Value	Fair Value
Derivatives assets:				
Commodity swaps and collars [a]	$ 154,656	$ 154,656	$	$
Interest rate swaps [a]			425	425
Derivatives liabilities:				
Commodity swaps and collars[a]	(4,887)	(4,887)	(231,049)	(231,049)
Net derivatives asset (liability)	$ 149,769	$ 149,769	$ (230,624)	$ (230,624)
Marketable securities [b]	$ 44,226	$ 44,226	$ 21,769	$ 21,769
Long-term debt [c]	$ 1,048,782	$ 1,058,069	$ (616,148)	$ (619,523)

(a) All derivatives are marked to market and therefore their book value is assumed to be equal to fair value.

(b) Marketable securities held in our deferred compensation plans which are marked to market.

(c) The book value of our bank debt approximates fair value because of their floating rate structure. The fair value of our senior subordinated notes is based on current market quotes.

At December 31, 2006, we had open swap contracts covering 73.6 Bcf of gas at prices averaging $9.29 per mcf. We also had collars covering 56.1 Bcf of gas at weighted average floor and cap prices of $7.42 to $10.49 per mcf and 4.5 million barrels of oil at weighted average floor and cap prices of $55.72 to $70.11 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax gain of $149.8 million at December 31, 2006. These contracts expire monthly through December 2008. Transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. In 2006, realized losses were $46.5 million relating to our hedges compared with losses of $171.1 million in 2005 and losses of $100.1 million in 2004. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting and were marked to market. This resulted in a gain of $86.5 million in 2006 versus a gain of $10.9 million in 2005. Gains and losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues. The ineffective portion of hedges that qualified for hedge accounting was a gain of $6.0 million in 2006 versus a loss of $3.4 million in 2005 and a gain of $712,000 in 2004.

The following table sets forth the hedging volumes by year as of December 31, 2006:

Period	Contract Type	Volume Hedged	Average Hedge Price	
Natural Gas				
2007	Swaps	96,336 Mmbtu/day	$9.13	
2007	Collars	98,500 Mmbtu/day	$7.13	$9.99
2008	Swaps	105,000 Mmbtu/day	$9.42	
2008	Collars	55,000 Mmbtu/day	$7.93	$11.39
Crude Oil				
2007	Collars	6,300 bbl/day	$53.46	$65.33
2008	Collars	6,000 bbl/day	$58.09	$75.11

In the past, we have used interest rate swap agreements to manage the risk that interest payments on amounts outstanding under the variable rate bank credit facility may be adversely affected by volatility in market interest rates. Our interest rate swap agreements ended on June 30, 2006.

Table of Contents

The combined fair value of net gains on oil and gas derivatives totaling $149.8 million appears as unrealized derivative gains and unrealized derivative losses on our consolidated balance sheet at December 31, 2006. Hedging activities are conducted with major financial or commodities trading institutions which we believe are acceptable credit risk. At times, such risk may be concentrated with certain counterparties. The credit worthiness of these counterparties is subject to continuing review.

(12) EMPLOYEE BENEFIT AND EQUITY PLANS

Stock and Option Plans

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and non-qualified options, stock appreciation rights (SARs), restricted stock awards, phantom stock rights and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee of the Board of Directors which is made up of outside independent directors. All awards granted under these plans have been issued at the prevailing market price at the time of the grant. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2003	5,746,703	$ 3.58
Granted	2,514,750	7.74
Exercised	(1,252,905)	3.46
Expired/forfeited	(135,443)	5.14
Outstanding at December 31, 2004	6,873,105	5.09
Granted	3,141,937	16.96
Exercised	(1,105,549)	4.84
Expired/forfeited	(167,188)	9.08
Outstanding at December 31, 2005	8,742,305	9.31
Granted	1,658,160	24.36
Stock options assumed in Stroud acquisition	652,062	19.67
Exercised	(2,051,237)	9.22
Expired/forfeited	(149,164)	18.32
Outstanding at December 31, 2006	8,852,126	$ 12.76

The following table shows information with respect to outstanding stock options and SARs at December 31, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted Average Exercise Price
$ 0.59 $4.99	2,570,002	2.85	$ 3.60	2,570,002	$ 3.60

5.00	9.99	1,375,008	2.13		7.01	660,046	7.02
10.00	14.99	368,673	2.85		11.50	196,412	12.13
15.00	19.99	2,821,048	3.78		16.98	844,274	17.58
20.00	24.99	1,554,395	4.26		24.20	97,885	24.04
25.00	30.80	163,000	4.33		26.55	21,150	25.85
Total		8,852,126	3.31	$	12.76	4,389,769	$ 7.74

Table of Contents

The weighted average fair value of an option/SAR to purchase one share of common stock during 2006 was $8.51. The fair value of each stock option/SAR granted during 2006 was estimated as of the date of grant using the Black-Scholes-Merton option pricing model based on the following assumptions: risk-free interest rate of 4.8%; dividend yield of 0.3%; expected volatility of 40.9%; and an expected life of 3.5 years.

As of December 31, 2006, the aggregate intrinsic value (the difference in value between exercise and market price) of the awards outstanding was $130.1 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable was $86.5 million and 3.2 years. As of December 31, 2006, the number of fully-vested awards and awards expected to vest was 8.7 million. The weighted average exercise price and weighted average remaining contractual life of these awards were $12.60 and 3.3 years and the aggregate intrinsic value was $128.8 million. As of December 31, 2006, unrecognized compensation cost related to the awards was $16.5 million, which is expected to be recognized over a weighted average period of 0.84 years.

For the year ended December 31, 2006, total stock-based compensation expense due to the adoption of SFAS 123(R) was $14.8 million. The total related tax benefits were $2.3 million. For the year ended December 31, 2006, cash received upon exercise of stock option/SARs awards was $16.3 million. Due to the net operating loss carryover for tax purposes, tax benefits realized for deductions that were in excess of the stock-based compensation were not recognized.

Restricted Stock Grants

In 2006, we issued 499,200 shares of restricted stock grants as compensation to directors and employees, at an average price of $24.43. The restricted grants included 15,000 issued to directors, which vest immediately, and 484,200 to employees with vesting over a three-year period. In 2005, we issued 192,500 shares of restricted stock grants (from treasury stock) as compensation to directors and employees, at an average price of $22.47. The restricted grants included 26,200 issued to directors, which vest immediately, and 166,300 to employees with vesting over a three-to-four year period. In 2004, we issued 121,400 shares of restricted stock grants as compensation to directors and employees, at an average price of $7.93. The restricted grants included 36,000 issued to directors, which vest immediately, and 85,400 to employees with vesting over a three-year period. We recorded compensation expense for restricted stock grants of $4.3 million in the year ended December 31, 2006 compared to $942,000 in 2005 and $567,000 in 2004.

A summary of the status of our unvested restricted stock outstanding at December 31, 2006 and changes during the twelve months then ended, is presented below:

	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006	238,107	$ 14.20
Granted	499,161	24.43
Vested	(212,129)	17.70
Forfeited	(23,628)	21.02
Outstanding at December 31, 2006	501,511	$ 22.58

401(k) Plan

We maintain a 401(k) Plan for our employees. The 401(k) Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. In 2005, we began matching contributions of up to 3% of salary in cash with the remainder of our contribution in common stock. All our contributions become fully vested after the individual employee has three years of service with us. Great Lakes also maintained a 401(k) plan for its employees which was merged into our plan effective January 1, 2005. In 2006, we contributed $1.9 million to the 401(k) Plan compared to $1.5 million in 2005 and $1.2 million in 2004. We do not require that employees hold the contributed Range stock in their account. Employees have a variety of investment options in the 401(k) Plan. Employees may, at anytime, diversify out of our stock, based on their personal investment strategy.

Stock Purchase Plan

In 1997, stockholders approved a stock purchase plan which authorized the sale of up to 1.75 million shares of common stock to officers, directors, key employees and consultants. Under the stock purchase plan, the right to purchase shares may be granted at prices ranging from 50% to 85% of market value. At December 31, 2006, there were no rights outstanding to purchase shares and there were 373,000 remaining shares authorized to be granted.

Table of Contents

Deferred Compensation Plan

In 1996, the Board of Directors adopted a deferred compensation plan (the Plan). The Plan gives directors, certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests in Range common stock or makes other investments at the individual s discretion. Great Lakes also had a deferred compensation plan that allowed certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee s discretion. In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan is intended to operate in a manner substantially similar to the old plans, subject to new requirements and changes mandated under Section 409A of the Internal Revenue Code. The old plans were frozen and will not receive additional contributions. The assets of all of the plans are held in a rabbi trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability and the carrying value of the deferred compensation plan liability is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense category on our consolidated statement of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our consolidated balance sheet reflects the market value of the securities held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholders equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the fair value of the liability is charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market expenses of $6.9 million in 2006 compared to $29.5 million in 2005 and $19.2 million in 2004. Since we actually issue the common shares to the Rabbi Trust, we do not incur additional cash expense other than the original fair market value of the stock when issued.

(13) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Net cash provided from continuing operations included:			
Income taxes paid to taxing authorities	$ 1,973	$ 615	$ 150
Interest paid	55,925	34,148	19,216
Non-cash investing and finance activities:			
Common stock issued under benefit plans	$ 2,058	$ 3,180	$ 2,122
6.5 million shares issued for Stroud acquisition	177,641		
Stock options (652,000) issued in Stroud acquisition	9,478		
Preferred stock converted to common stock			(50,000)
Asset retirement costs capitalized, excluding acquisitions [a]	25,821	(1,730)	3,994

[a] For information regarding purchase price allocations of businesses acquired see Note 3.

(14) COMMITMENTS AND CONTINGENCIES

Litigation

We are involved in various legal actions and claims arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

Table of Contents

Lease Commitments

We lease certain office space and equipment under cancelable and non-cancelable leases. Rent expense under such arrangements totaled $5.0 million, $2.2 million and $1.7 million in 2006, 2005 and 2004, respectively. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2007	$ 5,010
2008	5,308
2009	4,928
2010	3,867
2011	2,564
Thereafter	9,610
Sublease rentals	(222)
	$ 31,065

Other Commitments

As of December 31, 2006, we have contracts with various drilling contractors to use two drilling rigs in 2007 with terms of up to 2 years and minimum future commitments of $12.8 million in 2007 and $2.2 million in 2008. Early termination of these contracts at December 31, 2006 would have required us to pay maximum penalties of $11.3 million. We do not expect to pay any early termination penalties related to these contracts.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, and one-to-five-year contracts. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing, adjusted for quality and transportation. We sell to oil and gas purchasers on the basis of price, credit quality and service. For the year ended December 31, 2006, two customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those customers accounted for 25% of total oil and gas revenues. For the year ended December 31, 2005, four customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those four customers accounted for 56% of total oil and gas revenues. For the year ended December 31, 2004, two customers each accounted for 10% or more of total oil and gas revenue and combined sales to those two customers accounted for 25% of total oil and gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results.

Table of Contents

(16) EQUITY METHOD INVESTMENTS

On April 18, 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC (Whipstock), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the common stock of Whipstock.

We account for our investment in Whipstock under the equity method of accounting pursuant to Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. Under this method, we record our proportionate share of Whipstock s net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. There were no dividends or partnership distributions received from Whipstock during the year ended December 31, 2006. Whipstock follows a calendar year basis of financial reporting consistent with Range and our equity in Whipstock s earnings from the acquisition date through December 31, 2006 is included in our results of operations for 2006 in other revenue. In determining our proportionate share of the net earnings of Whipstock, certain adjustments are required to be made to Whipstock s reported results. These adjustments are made to eliminate the profits recognized by Whipstock for services provided to Range. For the year ended December 31, 2006, our equity in the earnings of Whipstock of $548,000 was reduced by $1.1 million in order to eliminate the profit on services provided to Range. Range and Whipstock have entered into an agreement whereby Whipstock will provide Range with the right of first refusal such that Range will have the opportunity to secure services from Whipstock in preference to and in advance of Whipstock entering into additional commitments for services with other customers. All services provided to Range will be at Whipstock s usual and customary terms. We also evaluate our equity method investment for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee s industry. These indicators were not present, and as a result, we did not recognize any impairment charges related to our investment in Whipstock for the year ended December 31, 2006.

Summarized financial information of investees accounted for under the equity method of accounting is as follows:

	2006 ($ in thousands)
Balance Sheet	
Current assets	$ 5,871
Non-current assets	30,261
Current liabilities	(5,458)
Non-current liabilities	(4,035)
Members equity	26,639
Income Statement	
Total revenues	$ 23,235
Gross profit	7,653
Income from operations	3,487
Interest expense	(198)
Net income	3,289

Our carrying value of our equity method investment is $300,000 higher than the underlying net assets of the investee. This basis difference is being amortized into earnings over five years.

(17) SUBSEQUENT EVENTS

On February 13, 2007, we sold our Austin Chalk properties for net sales proceeds of $80.4 million. These properties were classified as Assets Held for Sale at December 31, 2006. See also Note 3 and Note 4.

Table of Contents

(18) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years.

	2006				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 176,338	$ 157,620	$ 172,647	$ 177,323	$ 683,928
Transportation and gathering	77	898	1,034	498	2,507
Mark-to-market on oil and gas derivatives	11,281	17,503	54,950	2,757	86,491
Other	1,432	1,572	249	3,549	6,802
Total revenues	189,128	177,593	228,880	184,127	779,728
Costs and expenses					
Direct operating	19,662	20,541	24,784	27,237	92,224
Production and ad valorem taxes	9,727	8,669	9,985	8,534	36,915
Exploration	10,077	7,778	16,512	10,885	45,252
General and administrative	11,330	12,514	12,170	13,872	49,886
Deferred compensation plan	4,479	(2,188)	(2,638)	7,220	6,873
Interest expense	10,551	12,003	16,896	18,127	57,577
Depletion, depreciation and amortization	34,567	36,833	46,243	52,018	169,661
Total costs and expenses	100,393	96,150	123,952	137,893	458,388
Income from continuing operations	88,735	81,443	104,928	46,234	321,340
Income tax					
Current	578	622	615	97	1,912
Deferred	32,482	30,116	38,899	20,317	121,814
	33,060	30,738	39,514	20,414	123,726
Income from continuing operations	55,675	50,705	65,414	25,820	197,614
Discontinued operations, net of taxes		565	(14,084)	(25,393)	(38,912)
Net income	$ 55,675	$ 51,270	$ 51,330	$ 427	$ 158,702
Earnings per common share:					
	$ 0.43	$ 0.39	$ 0.48	$ 0.19	$ 1.48

Basic income from continuing operations										
discontinued operations						(0.11)		(0.19)		(0.29)
net income	$	0.43	$	0.39	$	0.37	$		$	1.19
Diluted income from continuing operations	$	0.41	$	0.37	$	0.46	$	0.18	$	1.42
discontinued operations				0.01		(0.10)		(0.18)		(0.28)
net income	$	0.41	$	0.38	$	0.36	$		$	1.14

Table of Contents

			2005		
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 107,415	$ 118,723	$ 142,055	$ 156,881	$ 525,074
Transportation and gathering	528	631	703	599	2,461
Mark-to-market on oil and gas derivatives				10,868	10,868
Other	17	330	(968)	(1,942)	(2,563)
Total revenues	107,960	119,684	141,790	166,406	535,840
Costs and expenses					
Direct operating	14,808	17,419	16,902	17,983	67,112
Production and ad valorem taxes	5,755	7,034	8,457	10,270	31,516
Exploration	3,271	9,124	7,725	10,484	30,604
General and administrative	6,603	6,241	9,019	11,581	33,444
Deferred compensation plan	4,067	5,276	17,450	2,681	29,474
Interest expense	8,584	9,547	9,910	10,756	38,797
Depletion, depreciation and amortization	29,762	30,436	32,900	34,416	127,514
Total costs and expenses	72,850	85,077	102,363	98,171	358,461
Income before income taxes	35,110	34,607	39,427	68,235	177,379
Income tax					
Current			331	740	1,071
Deferred	13,107	12,946	14,431	24,813	65,297
	13,107	12,946	14,762	25,553	66,368
Net income	$ 22,003	$ 21,661	$ 24,665	$ 42,682	$ 111,011
Earnings per common share:					
Basic	$ 0.18	$ 0.18	$ 0.19	$ 0.33	$ 0.89
Diluted	$ 0.18	$ 0.17	$ 0.19	$ 0.32	$ 0.86

(19) SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities, (SFAS No. 69). Our natural gas and oil producing activities are conducted onshore within the continental United States and offshore in the Gulf of Mexico.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [a]

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Oil and gas properties:			
Properties subject to depletion	$ 3,414,964	$ 2,519,454	$ 2,082,236
Unproved properties	226,263	28,636	14,790
Total	3,641,227	2,548,090	2,097,026
Accumulated depreciation, depletion and amortization	(964,551)	(806,908)	(694,667)
Net capitalized costs	$ 2,676,676	$ 1,741,182	$ 1,402,359

[a] Includes capitalized asset retirement costs and the associated accumulated amortization.

F-32

	Year Ended December 31, 2006	2005 (in thousands)	2004
Acquisitions:			
Acreage purchases	$ 79,762	$ 20,674	$ 9,690
Unproved leasehold	132,821		4,043
Proved oil and gas properties	209,262	131,748	522,126
Purchase price adjustment [b]	147,062	20,966	79,352
Asset retirement obligations	896	119	17,524
Development	464,586	252,574	144,007
Exploration [c]	70,870	59,539	31,830
Gas gathering facilities:			
Acquisitions		8	15,539
Exploratory	3,418		
Development	16,272	11,415	4,778
Subtotal	1,124,949	497,043	828,889
Asset retirement obligations	25,821	(1,730)	3,994
Total costs incurred	$ 1,150,770	$ 495,313	$ 832,883
Discontinued operations:			
Acquisitions	$ 140,110	$	$
Development	$ 15,012	$	$

(a) Includes cost incurred whether capitalized or expensed.

(b) Represents non-cash gross up to account for differences in book and tax basis.

(c) Includes $45,252, $30,604 and $21,219 of exploration costs expensed in 2006, 2005 and 2004, respectively. Exploration

expense
includes $3,079
and $1,250 of
stock-based
compensation in
2006 and 2005.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by our engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2006 to estimate reserve information were $57.66 per barrel for oil, $25.98 per barrel for natural gas liquids and $5.24 per mcf for gas, using benchmark prices of $61.05 per barrel and $5.64 per Mmbtu. The average realized prices used at December 31, 2005 to estimate reserve information were $57.80 per barrel for oil, $36.00 per barrel for natural gas liquids and $9.83 per mcf for gas, using benchmark prices of $61.04 per barrel and $10.08 per Mmbtu. The average realized prices used at December 31, 2004 to estimate reserve information were $40.44

per barrel for oil, $25.05 per barrel for natural gas liquids and $6.05 per mcf for gas, using benchmark prices of $43.33 per barrel and $6.18 per Mmbtu.

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents (Mmcfe)
Proved developed and undeveloped reserves:			
Balance, December 31, 2003	33,023	486,404	684,541
Revisions	(312)	(24,251)	(26,111)
Extensions, discoveries and additions	5,515	122,790	155,875
Purchases	7,062	421,775	464,149
Sales	(3,622)	(9,568)	(31,303)
Production	(3,500)	(50,722)	(71,726)
Balance, December 31, 2004	38,166	946,428	1,175,425
Revisions	2,499	809	15,802
Extensions, discoveries and additions	7,932	169,785	217,377
Purchases	2,343	71,569	85,626
Sales	(5)	(177)	(205)
Production	(4,043)	(63,004)	(87,263)
Balance, December 31, 2005	46,892	1,125,410	1,406,762
Revisions	(42)	(48,609)	(48,863)
Extensions, discoveries and additions	10,871	314,261	379,491
Purchases	242	121,683	123,133
Sales	(4)	(1,500)	(1,522)
Production	(4,252)	(75,267)	(100,775)
Balance, December 31, 2006 [a]	53,707	1,435,978	1,758,226
Proved developed reserves:			
December 31, 2004	27,715	580,006	746,299
December 31, 2005	33,029	724,876	923,050
December 31, 2006	37,750	875,395	1,101,895

[a] The December 31, 2006 balance excludes reserves associated with the Austin Chalk properties that are shown as Assets Held

for Sale on our balance sheet. The total proved developed and undeveloped reserves for these assets at December 31, 2006 were 42.3 Bcfe which is comprised of 39.3 Bcfe of gas.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by SFAS No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Table of Contents

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.

2. Estimated future cash inflows are calculated by applying current year-end prices of natural gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year.

3. Future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.

4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Future cash inflows	$ 10,192,067	$ 13,520,985	$ 7,109,349
Future costs:			
Production	(2,575,212)	(2,266,828)	(1,472,484)
Development	(1,225,710)	(825,261)	(601,447)
Future net cash flows before income taxes	6,391,145	10,428,896	5,035,418
Future income tax expense	(1,999,934)	(3,496,799)	(1,523,915)
Total future net cash flows before 10% discount	4,391,211	6,932,097	3,511,503
10% annual discount	(2,388,987)	(3,547,787)	(1,762,092)
Standardized measure of discounted future net cash flows	$ 2,002,224	$ 3,384,310	$ 1,749,411

Table of Contents

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	As of December 31,		
	2006	2005	2004
		(in thousands)	
Beginning of period	$ 3,384,310	$ 1,749,411	$ 1,002,981
Revisions to previous estimates:			
Changes in prices	(2,390,159)	1,633,812	129,916
Revisions in quantities	(91,793)	59,244	(59,591)
Changes in future development costs	(623,607)	(367,732)	(399,562)
Accretion of discount	488,737	239,636	139,582
Net change in income taxes	733,846	(856,115)	(254,114)
Purchases of reserves in place	231,314	321,022	1,059,294
Additions to proved reserves from extensions, discoveries and improved recovery	712,902	814,973	355,742
Production	(554,788)	(425,902)	(248,891)
Development costs incurred during the period	223,158	143,918	72,144
Sales of natural gas and oil	(2,859)	(769)	(71,441)
Timing and other	(108,837)	72,812	23,351
End of period	$ 2,002,224	$ 3,384,310	$ 1,749,411

Table of Contents

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated May 10, 2006, by and among Range Resources Corporation, Range Acquisition Texas, Inc. and Stroud Energy, Inc. (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 16, 2006)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.2 to our Form 10-K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7.375% Senior Subordinated Notes due 2013 (included as an exhibit to exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Form of 6.375% Senior Subordinated Notes due 2015 (included as an exhibit to exhibit 4.4 hereto)
4.4	Indenture dated March 9, 2005 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
4.5	Form of 7.5% Senior Subordinated Notes due 2016 (included as an exhibit to exhibit 4.6 hereto)
4.6	Indenture dated May 23, 2006 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 23, 2006)
10.1*	Third Amended and Restated Credit Agreement as of October 25, 2006 among Range (as borrowers) and J.P.Morgan Chase Bank, N.A. and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.2	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective December 28, 2004 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.3	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.5 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.4	Range Resources Corporation 2005 Equity-Based Compensation (incorporated by reference to Exhibit 10.7 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)

10.5	First Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.8 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.6	Second Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.7	Third Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.8	Lomak 1989 Stock Option Plan dated March 13, 1989 (incorporated by reference to Exhibit 10.1(d) to Lomak s Form S-1 (File No. 33-31558) as filed with the SEC on October 13, 1989)
10.9	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.1 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.10	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-44821) as filed with the SEC on January 23, 1998)
10.11	Lomak 1994 Outside Directors Stock Option Plan (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.12	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.13	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

Table of Contents

Exhibit No.	Description
10.14	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.15	Fourth Amendment to the Lomak 1994 Outside Directors Stock Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.16	2004 Non-Employee Director Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.17	Lomak 1997 Stock Purchase Plan, as amended, dated June 19, 1997 (incorporated by reference to Exhibit 10.1(1) to Lomak s Form 10-K (File No. 001-12209) as filed with the SEC on March 20, 1998)
10.18	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.19	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28, 1999 (incorporated by reference to Exhibit 4.3 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.20	Third Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.21	Fourth Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)
10.22	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.23	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.24	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.25	Range Resources Corporation Executive Change in Control Severance Benefit Plan dated March 28, 2005 (incorporated by reference to exhibit 10.1 to our Form 8-k (File No. 001-12209) as filed with the SEC on March 31, 2005)
14.1	Amended Code of Business Conduct and Ethics, as amended (incorporated by reference to Exhibit 10.4 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 22, 2005)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Public Accounting Firm

23.2*	Consent of H.J. Gruy and Associates, Inc., independent consulting engineers
23.3*	Consent of DeGoyler and MacNaughton, independent consulting engineers
23.4*	Consent of Wright and Company, independent consulting engineers
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed herewith.

** Furnished herewith.