“precious resources”

RANGE RESOURCES

ANNUAL REPORT 2005

people

inventory

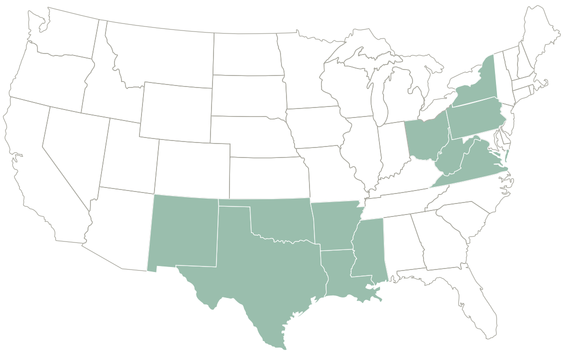
acreage

RANGE RESOURCES

Precious Resources. Like other exploration and production companies, Range is engaged in the daily pursuit of two of the world's most critical natural resources – crude oil and natural gas. We believe we have three precious resources that set us apart in this pursuit: our team of dedicated, talented **people**; a large, multi-year **inventory** of drilling projects; and an expansive **acreage** position covering 3 million acres. These three precious resources form a strong foundation that supports our growth today and well into the future.

"We entered 2006 with a very large 3 million acreage position and the largest drilling inventory in our history."

Charles L. Blackburn
Chairman



Areas of Operation

Dear Fellow Shareholders

2005 was a watershed year for Range Resources. Record financial results were achieved and our operating results were outstanding. Production increased 22% and reserves rose 20%, each setting record highs. These results were achieved while maintaining our top-quartile finding cost structure. Our strategy of a technically driven exploration and production company focused on drillbit growth coupled with complementing acquisitions is paying off with attractive returns on capital invested and exceptional returns for shareholders. During 2005, Range's stock price appreciated 93%, adding $1.5 billion in market value for our shareholders. Also, late in the year we completed a 3-for-2 stock split, effectively increasing the common stock dividend rate by 50%.

The Company's 2005 financial results were the best in our history. Revenues increased 67% to $536 million, while cash flow jumped 74% to $363 million. Net income nearly tripled to $111 million with earnings per share increasing 126% to $0.86. The drivers for the increased financial results were the 22% increase in production and a 37% rise in realized prices. After adjustment for hedging, realized prices averaged $6.03 per mcf and $38.71 per barrel.

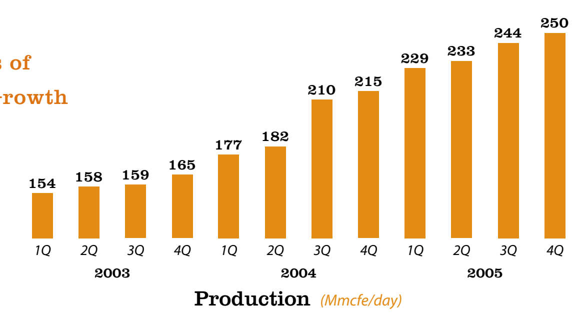
In 2005, we continued to simplify and strengthen the Company's capital structure. Total assets and stockholders' equity increased 27% and 23% respectively, while debt fell slightly. The debt-to-capitalization ratio was reduced to 47% at year-end and is expected to decline to the 40% target level in 2006.

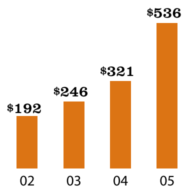
Proved reserves at year-end totaled 1.4 Tcfe, a 20% increase. We replaced 365% of 2005 production at an attractive all-in cost of $1.46 per mcfe. The pretax present value of the reserves, based on constant year-end prices discounted at 10%, totaled $4.9 billion. This represents a $2.5 billion or 104% increase from the prior year-end. The pretax present value rose from $24.45 per share at year-end 2004 to $37.85 per share at year-end 2005. Based on these reserves, our reserve life index rose slightly to 15.3 years.

During 2005, Range expended $290 million to drill 841 wells and recomplete 114 others, achieving a 98% success rate. Drilling alone replaced 249% of production, a record high. In addition, we completed $132 million of acquisitions during the year, adding reserves at an attractive price and expanding the drilling inventory.

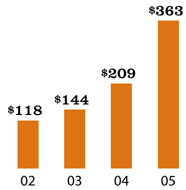
Looking ahead, Range entered 2006 in an enviable position. Our large, multi-year inventory of low-risk drilling projects gives us confidence that we can, once again,

12 Consecutive Quarters of Increasing Production Growth

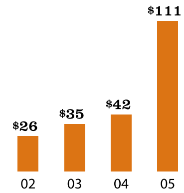




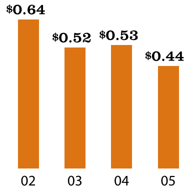
Revenues *(Millions)*



Cash Flow *(Millions)*



Net Income *(Millions)*



Debt *(per mcfe)*

deliver double-digit production growth in 2006. We have set our 2006 capital budget at $429 million to fund the drilling of 1,065 wells and 94 recompletions. Our 2006 drilling program remains heavily weighted toward the exploitation of our large inventory of development projects. In addition, several high-potential exploration projects will be tested. Higher production, coupled with the rolling off of the last of our lower price oil and gas hedges, positions us to deliver record results again in 2006.

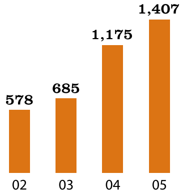
Our success is based on a strategy of growing production and reserves at top-quartile finding and development costs. As of year-end 2005, we had delivered 12 consecutive quarters of increasing production growth, despite an array of obstacles including hurricane shut-ins, pipeline curtailments and a tightening oilfield service sector. The goal for 2006 is to extend production growth to 16 consecutive quarters while maintaining our competitive cost structure. To accomplish this, we must continue generating attractive returns through the wise investment of capital. We believe there are three vital ingredients to consistently succeed over the long term. First, is to develop high-quality technical and operating teams that generate attractive opportunities and consistently deliver superior operating results. Second, is to build a large, multi-year inventory of repeatable drilling projects. Third, is to develop and maintain a large acreage position.

This annual report focuses specifically on these three important components – our people, our drilling inventory and our acreage. We entered 2006 with a very high-quality team of technical and operating professionals focused on building per share value, the largest drilling inventory in our history consisting of more than 7,700 projects and a very large 3 million acreage position. As you read and study this report, we hope that you will agree with us that Range is very well positioned to continue to deliver exceptional returns for its shareholders.

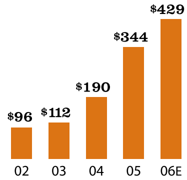
Over the past five years, we have transformed Range into a top-tier independent oil and gas company. Reserves have grown almost 2.5 times while production has jumped more than 1.5 times. Most importantly, our shareholders have been the direct beneficiaries as our stock price has increased 475%. In today's business world, too many times credit for such performance is given to senior management. In the case of Range, we want to make it clear that the credit goes to our team of nearly 600 employees. They are the ones who generate the opportunities and execute the plan each and every day. We salute each of them for a job exceedingly well done. We also thank our fellow directors and, most importantly, our shareholders for your steadfast support. ■

Charles L. Blackburn
Chairman

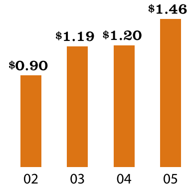
John H. Pinkerton
President/Chief Executive Officer



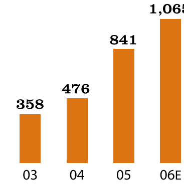
Proved Reserves *(Bcfe)*



Capital Expenditures *(Millions)*



Finding Costs *(per mcfe)*



Wells Drilled

“Range is very well positioned to continue to deliver exceptional returns for its shareholders.”

John H. Pinkerton
President and Chief Executive Officer

people

Our Most Valuable Asset

We count our people first among our most precious assets. An oil and gas company is no more than the sum of its people who generate creative ideas, execute on those ideas and support the success of the operating teams in a myriad of ways. At Range, our employee base now numbers almost 600, and our technical team is approaching 100 strong. This team of technical experts, which includes geologists, geophysicists, engineers and landmen, is generating fresh and exciting new ideas on a continuous basis. Through their passion, creativity, drive and ingenuity, Range has delivered 12 consecutive quarters of steady production and reserve growth at top-quartile finding and development costs. Our people are the reason for our success. They are our lifeblood.

At Range, we are passionate about executing our game plan. That's why we place a strong emphasis on hiring the best people possible for our team. Geologists. Geophysicists. Engineers. Landmen. They are not created equally. It takes a special group of athletes to take a sports team to the play-offs; similarly, it takes a special technical team to drive top-tier success at an oil and gas company. We look for individuals with keen intelligence and intuitive skills, combined with excellent technical knowledge, experience, creativity, optimism and a deep desire to succeed. We believe if you hire top-quality people, they will perform for you. It is in their nature. When they are playing alongside of other top talent, they are further challenged to even greater achievements. Over the past several years we have focused intently on growing and assembling a winning technical team. In the process, we believe we are attracting an increasing number of "first round draft picks," not the least of which is Mark Whitley, our new Senior Vice President. A respected expert with more than 30 years of experience at companies such as Shell Oil and Mitchell Energy, Whitley is well-known for leading the team that unlocked the Barnett shale play in the Fort Worth Basin. With Range, Whitley will not only oversee our rapidly expanding shale play operations in all of our divisions; he will also manage the Company's overall activities in the Permian Basin and East Texas.

"With an experienced team willing to apply new technology, we have reduced our drill time in some key areas in the Midcontinent by 30%."

Cory West, *Drilling Manager – Midcontinent*

The management team at Range is composed of 27 seasoned oil and gas professionals. And the senior management team, pictured above, has a combined total of 200 years of industry experience. Notably, each member of the team has achieved significant career success. They have founded and built companies, led extraordinary technical achievements and quickly moved up the ranks with increasing responsibilities. They have complementary skill sets. Some bring a strong technical focus, while others bring a financial or acquisitions background. This is a very cohesive group, supporting each other, challenging each other, but always putting the best interests of Range and its shareholders first. Their common goals are more important than individual agendas. Perhaps the most important key to their success, however, lies in their integrity. They lead through example, encouraging open communication and respect at all levels of the organization.

At Range, we go out of our way to create a corporate culture where people thrive and are encouraged to develop their talents to the fullest. This is a flat organization. Without multiple layers of bureaucracy to bottleneck projects, we can move through approvals quickly, often beating the competition with our fleet-footed approach. For example, we were quick to secure shale leases in the emerging Appalachian and West Texas areas. We strive to equip our people with the tools they need – whether it be advanced training, new or reprocessed seismic data, or additional personnel – to achieve the increasingly challenging drilling programs we are setting. As a result, not only is this team ramping up the number of wells it is drilling with each passing year, it is also including more technically difficult projects than in the past.

Our work to create a rewarding, high-performance culture is paying off. At a time when competition for experienced oil and gas personnel is extremely intense, we can report a very low turnover rate. In this business, more than most, experience is a key element of success. We look for technical people who have experience in the basins where we work. That's because we know that it

Pictured left to right:

Roger S. Manny
Senior Vice President and Chief Financial Officer

Jeffrey L. Ventura
Executive Vice President and Chief Operating Officer

John H. Pinkerton
President and Chief Executive Officer

Mark D. Whitley
Senior Vice President – Permian and Engineering Technology

Chad L. Stephens
Senior Vice President – Corporate Development

Rodney L. Waller
Senior Vice President – Chief Compliance Officer and Secretary

Steven L. Grose
Senior Vice President – Appalachia

"I value the people in my division for their technical expertise, but more than that, I value them for their character."

Paul Blanchard
Vice President – Midcontintent

takes some trial and error to climb the learning curve of a basin, to decipher the seismic signatures and to achieve a high drilling success rate. A cohesive team is critical in other areas as well. For example, some operators have ramped up drilling to the point that they are hiring inexperienced people. These inexperienced people often inadvertently create downtime and inefficiencies. To the contrary, our experienced operating teams are reducing drill times, a tremendous benefit as field service costs continue to rise.

In addition to respecting our employees, we also strive to reward their initiative and hard work. Range is one of only a few companies that provides equity incentives to all levels of employees. The idea is to tie the goals of the employee to the goals of the Company and its shareholders. If the Company is performing well, and the stock is performing well, all employees share in the upside. This philosophy of hiring the best and rewarding them for their performance pays dividends to our shareholders. Over the past five years, our stock price has increased 475%, benefiting our shareholders and our employees alike. In 2005, the number of wells we drilled increased by 77%, while the number of personnel increased by only 14%. Our people are performing at a very high level. As you will see in the remainder of this report, they are generating many exciting prospect ideas that are building and high-grading our drilling inventory, while expanding our acreage position through negotiated land, acquisition and joint venture agreements.

At Range, our philosophy about our people is very simple. We hire the best team members we can, people who want to work in a competitive environment that challenges them and puts them together with other top talent. Then we give them the tools, respect and support they need to do what comes to them naturally: succeed. While acreage, drilling inventory, technology and financial stability are important, none are as important as the quality, drive and commitment of the individuals who make up Range. ■

"Our culture attracts top-quality people. We have a reputation for an open environment where everyone is valued and each person's ideas are heard."

Carol Culpepper, *Human Resources Manager*

inventory

Our Growth Driver

Over the past three years, our drilling inventory has more than tripled and now encompasses more than 7,700 projects. Equally important, our inventory of drilling projects is of a higher quality with greater reserve potential than at any time in our history. At year-end, our proved reserves were 1.4 Tcfe, an increase of 20% over the prior year. In 2005, we replaced 249% of our production through the drillbit, a direct reflection on the quality of our inventory. Our large, multi-year portfolio of low-risk projects, coupled with a number of high-potential exploratory and emerging plays, provides the foundation to drive our future growth.

Tight gas sands

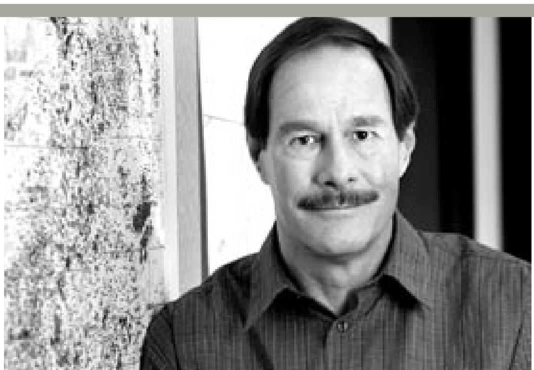
The Company's greatest concentration of low-risk development projects lies in the tight gas sand fields of Appalachia, with 3,400 locations currently in inventory. Additional potential comes from a tight gas acreage position that covers approximately 1 million acres. Historically, the Company has achieved a 99% success rate drilling this highly repeatable play, which consists of shallow, low-cost, long-lived wells. Drilling continues to ramp up in the play, with 479 wells planned for 2006 versus 439 wells drilled in 2005.

Coal bed methane

Range elevated another highly repeatable play – coal bed methane – with the 2004 purchase of three key fields in Virginia and West Virginia. Between the Nora field in Virginia and the adjacent step-out field, Haysi, Range now has 2,700 low-risk CBM locations to drill on 60-acre spacing. These properties, which cover 287,000 acres, are yielding long-lived, low-decline reserves at excellent finding costs of less than $1.00 per mcf. In 2006, the Company plans to drill 235 wells at Nora and Haysi compared to 175 in 2005. Range also has several emerging CBM plays. The 77,000-acre Widen field in West Virginia, along with four project areas in Pennsylvania, are in various stages of coring, testing and drilling. Assuming success, as many as 1,300 locations on currently held acreage could be generated by these emerging plays.

Field rejuvenations

In 2004, Range began testing the rejuvenation of an oil field in northern Oklahoma where production dates back to the 1920s. With improved technologies and higher oil prices, commercial production has been re-established through dewatering. This shallow play is low-risk and



"We are identifying multiple drilling opportunities in fields once considered mature. At West Fuhrman Mascho, a 75-year-old field in West Texas, we achieved peak production in 2005."

Pat Stevens, *District Engineer*

Large, Multi-Year Drilling Inventory

Reserve Risk Profile		Gross Wells in Inventory	Net Bcfe Unrisked Reserves
High	*Mississippi Norphlet*	24	229
Medium	*Gulf Coast Oligocene/Miocene, Appalachia Trenton Black River, Midcontinent Hunton*	132	225
Low	*Midcontinent Morrow/Springer, Midcontinent Tonkawa, Appalachia Oriskany, East Texas Stacked Pay, Appalachia Coalbed Methane, Appalachia Clinton/Medina, Appalachia Upper Devonian, Permian Cisco/Canyon, Permian San Andres, Midcontinent Brown Dolomite/Wolfcamp*	7,588	1,419
	TOTAL	7,744	1,873

• 1.4 Tcf unbooked reserves, primarily low-risk tight sand and CBM reserves

PROVED RESERVES – 1.4 Tcfe
Solid asset base to build from
• *Long-life, high-margin domestic reserves*

UNBOOKED DRILLING INVENTORY – 1.4 Tcfe
Predictable production growth
• *Large, multi-year inventory Over 7,700 drilling locations*

EMERGING PLAYS – 2.0+ Tcfe
Substantial future potential
• *Emerging plays Shale, CBM, exploration*

GROWTH

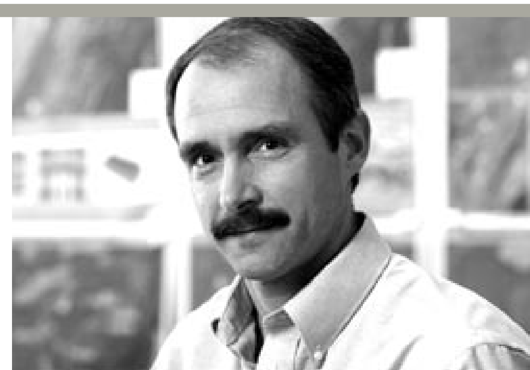
TOTAL POTENTIAL – 4.8+ Tcfe
Solid base of proved reserves with > 2x unbooked potential

highly repeatable. More than 200 potential drilling locations have been identified, and a 42-well program is slated for 2006.

Elsewhere, in West Texas, a redevelopment project was undertaken in 2002 at the West Fuhrman Mascho field. Since 2000, 135 producers and 23 injectors have been drilled in the field, increasing production roughly sevenfold from 500 barrels of oil per day to 3,400 today. In 2006, a total of 81 wells are scheduled, 23 of which aim to extend the waterflood program to the south.

Stacked pay areas

The Company's diverse portfolio of projects includes several low-risk stacked pay areas, where a single well bore targets multiple prospective zones. This approach reduces dry hole risk and helps contain drilling costs. For example, in the Watonga-Chickasha region of western Oklahoma, Range targets up to six pay zones from 8,000 to 11,000 feet. In 2005, Range encountered significant pay in the Atoka/Morrow formation and identified 18 additional locations, several of which are planned to drill in 2006. In the Texas Panhandle, Range drilled a significant Hunton discovery in 2005, establishing the first economic Hunton production in Roberts County, Texas. Additional drilling success occurred in five additional pay zones. Fifteen wells are budgeted here in 2006. In East Texas, Range is testing several higher risk, high-potential projects targeting stacked pay in the Woodbine and Austin Chalk formations at depths between 13,000 to 16,000 feet. Four wells have drilled to date. Two of the wells were completed in the Woodbine, while two were completed in the Austin Chalk. The four wells are currently producing at a combined net rate of 4.5 Mmcfe per day.



“We now have roughly 3,400 tight gas sand locations in inventory. This play is highly repeatable, and it just keeps on growing.”

Steve Rupert
Vice President Operations – Appalachia

Exploratory plays

Over the past several years, Range has begun targeting some higher risk, higher potential plays in deeper formations. For example, in Appalachia, the Company has accumulated 140,000 net acres in the deep Trenton Black River play, where other operators have drilled prolific wells producing as much as 10-20 Mmcfe per day at depths of 10,000 to 12,500 feet. In 2005, we drilled our first two deeper TBR wells. One of the wells is awaiting a completion attempt, while the other well was a dry hole. Late in 2005, Range announced a joint venture to develop deep Trenton Black River targets in southwestern Pennsylvania covering 17,000 acres with a subsidiary of Talisman Energy, the industry leader in the play. The joint venture's first well is expected to drill in the first half of 2006. In the Company's deepest drilling project to date, we are currently participating in a 23,500-foot wildcat in the deep Anadarko basin of Oklahoma. The well has already logged pay in several shallower zones. The Company has accumulated almost 12,000 gross acres in this area and is pursuing additional leasehold. While these wells are higher risk projects, they have the potential to generate initial production rates in excess of 10-20 Mmcfe per day. Four additional wells are planned in this area for 2006.

Shale plays

In 2004, we began testing a shale gas project in Pennsylvania. To date, six vertical wells and two horizontal wells have been drilled. Two wells are currently producing commercial quantities of natural gas, while the other six wells are in various stages of drilling or completion. While very early, initial results are encouraging. Assuming continued success, the Company plans to drill 10 vertical wells and three horizontal wells in 2006. Range also plans to test two Texas shale plays in 2006. Leasing continues, 3-D seismic surveys are planned and a second half spud is planned in each project area. With 266,000 prospective acres, we currently estimate 2 Tcfe of unrisked reserve potential in our three primary emerging shale plays.

Range has a number of other plays, from low-risk Permian basin development to onshore Gulf Coast exploration projects and additional emerging concepts that are in their infancy. Our current drilling inventory of over 7,700 projects, combined with the potential of our emerging plays, positions Range very well for the future.

“We have in excess of 3,000 potential coal bed methane locations, and we have the green light to bring these low-cost reserves to market.”

Jerry Grantham
Vice President – Coalbed Methane

acreage

Acres of Opportunity

Over the last three years, our acreage position has increased significantly, from 1.7 million (850,000 net) acres to more than 3.0 million (2.5 million net) acres currently. Equally important, success with our shale plays, deeper exploratory projects and stacked pay opportunities could add significantly to our undeveloped acreage position. In the oil and gas business, acreage means opportunity. At Range, we believe our exceptional land position has us well positioned for future growth.

Significantly, almost two-thirds of our acreage is found in the Appalachian basin. This is the largest onshore basin in the United States. Ironically, with more than 1 million wells drilled to date, it is one of the least explored basins. Less than one percent of the wells has been drilled below 7,500 feet, and fewer than 200 of the wells have been drilled below 10,000 feet. In addition, a vast majority of the acreage is held by shallow production, allowing us to explore for deeper structures without the time pressure of expiring leases.

In the past, drilling in Appalachia targeted long-lived, shallow development wells. Competition for acreage was minimal, and land prices remained low. Today it's a different story. A number of operators are now aggressively looking for Appalachian acreage as coal bed methane, shale and deep drilling opportunities are developing or have been made commercial due to the higher commodity price environment and advanced technologies.

For the past 30 years, Range has been active in the basin, amassing roughly 2 million leasehold acres in support of our manufacturing-style shallow development drilling. The majority of this acreage was acquired at prices below $50 per acre. With interest in the basin's shale potential heating up, Range now finds itself in the middle of the fairway in terms of prospective shale acreage. Currently, we believe we have 235,000 acres of leasehold in Appalachia that is prospective for shale development, and we are continuing to pursue additional leasehold. Should the play prove successful, Range already has a sizeable acreage position, acquired at a nominal cost.

Typically, we grow our acreage through three key avenues: agreements with industry partners, leasehold acquisitions and property acquisitions. Our targeted

“A large percentage of our acreage in Appalachia could have undeveloped potential, given the emerging shale gas and deeper exploratory plays.”

Mark Acree, *Vice President Land – Appalachia*

approach to leasehold acquisition is based on our technical team’s evaluation. When they identify what they believe to be high-quality prospects, usually with multiple prospective horizons, we make a concerted effort to lease the desired locations. For example, we had an area in Oklahoma where we had been drilling for a number of years and had developed excellent technical knowledge in the region. In 2004, we approached a major oil company that had acreage co-mingled in our field. After we demonstrated our geological understanding of the play, ability to perform and willingness to commit to a significant drilling program, they accepted our proposal and signed a co-development agreement, effectively doubling our undeveloped acreage in the play. We gained access to acreage, and they gained value by placing inactive acreage into play – a mutually beneficial agreement.

Our Courson Ranch project in the Texas Panhandle is another example of how we grow our acreage. In 2002, we were approached by a group of independents who owned a soon-to-expire lease covering approximately 30,000 acres. Given our successful track record in the Morrow play, they were willing to negotiate an exploration agreement with us. The agreement provided Range access to the acreage and a 3-D seismic survey, while providing our partners with locations. As a result, we successfully drilled a number of seismically defined Morrow wells. Encouraged, we conducted a proprietary seismic shoot that identified locations in additional formations, including several deeper prospects. In 2004, we leased 4,000 acres of deep rights on the ranch and successfully tested two high-rate wells at depths below 10,000 feet. Range’s working relationships with both the mineral and surface owners allowed us to negotiate a transaction in 2005 providing us with an 88% working interest in the deep rights across the remainder of the ranch. These agreements added approximately 35,000 acres and multiple high-potential prospects to our inventory.

In addition to these types of singles and doubles, occasionally we hit a home run and acquire a sizeable producing property that is very accretive to our acreage position. Over the past three years, we have spent $740 million on acquisitions, acquiring 650 Bcfe of reserves at an average cost of $1.14 per mcfe. This investment increased our acreage position significantly, while adding

“We have been able to identify almost 235,000 acres prospective for shale development on leasehold in the Appalachian basin.”

Bill Zagorski
Vice President Geology – Appalachia

multiple new drilling locations. While we continue to evaluate acquisition properties on a regular basis, we will remain disciplined. Our current inventory and acreage position is expected to drive double-digit production growth in 2006 without the benefit of acquisitions. Our goal is to generate baseline growth through the drillbit and to complement that with acquisitions in our core areas where we have operational expertise. Given our strong drillbit growth, combined with our favorable inventory and acreage position, we can afford to wait for acquisitions that are attractive economically, geographically and operationally.

Our land teams work day-in and day-out to secure leases and handle all the attendant payments and paperwork associated with the contracts. They send brokers out into the field to contact landowners directly and negotiate agreements. Concurrently, we have an acquisitions team that is constantly evaluating producing properties as possible acquisition targets, while negotiating farm-ins, farm-outs, co-development agreements and joint ventures to further our acreage position. The oil and gas business is a depleting asset business. As properties are drilled, they need to be replaced. As leases expire, new ones need to be secured. It takes a lot of effort to stay ahead of the curve, but at Range we are doing just that.

Our goal is to remain focused on our long-term growth. Our desire is not to be the biggest, or the fastest growing, but to maintain a high rate-of-return for our investors over a long period of time. And experience has taught us that the best way to achieve this goal is by carefully tending to the precious resources that set us apart – our people, our drilling inventory and our acreage.

> "Acreage is the future of an oil and gas company, and with our 3 million gross acres, Range is well positioned for the future."

Fred Standefer
Vice President Land – Midcontinent

Eleven-Year Financial Highlights

(millions except per share data)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Revenues	41.2	75.3	145.4	142.9	189.1	200.6	219.6	191.6	245.8	320.7	535.9
Operating Margin	28.6	51.3	106.3	103.3	110.2	137.8	168.9	154.0	180.6	251.1	429.5
Net Income (loss)	4.4	12.6	(23.3)	(181.3)	(23.5)	36.6	17.7	25.8	35.4	42.2	111.0
Earnings per Share (diluted)	0.21	0.46	(0.87)	(4.71)	(0.47)	0.64	0.24	0.32	0.41	0.38	0.86
Cash Flow [(a)] *(a non-GAAP measure)*	21.5	42.5	81.8	56.0	59.9	93.7	131.8	118.0	143.8	208.6	363.4
Total Debt	83.1	116.8	487.1	727.3	576.6	458.1	392.2	368.0	358.2	620.6	616.1
Stockholders' Equity	99.2	117.5	197.0	125.7	103.2	159.9	235.6	206.1	274.1	566.3	696.9
Total Assets	214.8	282.5	758.8	914.0	732.2	671.8	682.5	658.5	830.1	1,595.4	2,019.0

(a) Cash flow from operations before changes in working capital plus exploration expense and other adjustments. See reconciliation following the 10-K.

In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in the Company's Form 10-K for the year ended December 31, 2005, which has been filed with the Securities and Exchange Commission.

"I recently nominated Range for a National Guard Patriot Award. As a Commander in the Guard of 124 soldiers, I often hear that employers give my men a hard time about weekend drills and deployments. I have even had soldiers lose their jobs. However, when I told my supervisor that I was going overseas for a year, he only asked, 'Well, you're coming back, right?' That said it all. It does my heart good to work for a Company that supports me in serving this great country."

Carl Dokter, *Exploration Geologist*

IN MEMORY

Robert E. Aikman

Robert E. Aikman, our longest standing outside director of the board, died in an automobile accident on November 4, 2005. Mr. Aikman had served on Range's board for the past 15 years. His lovely wife of 55 years, Rachel, also died in the accident.

Mr. Aikman attended the University of Oklahoma where he earned a B.S. degree, and he began his career in 1952 as a petroleum landman for Cities Service Oil Company. He and other family members formed the Aikman Brothers Corporation in 1960, and he went on to serve in management for a number of other oil and gas companies.

Bob, as he was known to us, was a friend as well as a colleague. We wish to commemorate a life well led. He played an important role in establishing the ground rules for our Company, encouraging its growth and shaping its success. For that we are very grateful.

More than that, he played an important role in our lives. His insight and wisdom guided us. His encouragement spurred us on. His questions intrigued and challenged us. He was an integral part of our corporate family, and he is deeply missed.

RANGE RESOURCES

www.rangeresources.com

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)
☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year-ended December 31, 2005
or

☐ 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 ✓ No____

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____ No ✓

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 ✓ No____

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. ☑

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 ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes____ No ✓

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, 2005 was $2,276,192,000.

As of February 20, 2006, there were 130,661,982 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 2006 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.

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RANGE RESOURCES CORPORATION

Annual Report on Form 10-K
Year Ended December 31, 2005

Disclosures Regarding Forward-Looking Statements

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission or 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,” “should,” “goal,” “anticipates,” “expects,” “believes,” “seeks,” “plans,” “estimates,” “intends,” “projects” or “targets” and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: 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 2005, our proved reserves had the following characteristics:

- 1.4 Tcfe of proved reserves;
- 80% natural gas;
- 66% proved developed;
- 78% operated;
- a reserve life of 15.3 years (based on fourth quarter 2005 production); and
- a pre-tax present value of $4.9 billion.

At year-end 2005, we owned 2,843,000 gross (2,381,000 net) acres of leasehold, plus over 400,000 royalty acres. We have built a multi-year inventory of drilling projects which includes over 7,700 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 four years, we have increased our proved reserves 143%, while production has increased 59% 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.

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. Such a strategy requires us to make significant investments in technical staff, acreage and seismic 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 Permian Basin of West Texas and eastern New Mexico, the East Texas Basin, the Texas Panhandle and Anadarko Basin of Western Oklahoma), Appalachian 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. By maintaining a large, multi-year inventory of drilling projects, we believe this increases our ability to consistently grow production and reserves over the next several years. Currently, we have over 7,700 identified drilling locations in inventory. In 2005, we drilled 841 gross (594 net) wells. In 2006, our capital program targets the drilling of 1,065 gross (789 net) wells.
- *Make Complementary Acquisitions.* We target complementary acquisitions in existing core areas and focus on acquisition candidates where our existing scientific knowledge is transferable and drilling results can be forecast with confidence. Over the past three years, we have completed $743.0 million 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 try to limit our exploratory expenditures to no more than 20% of our annual capital budget per year. Most of our exploratory drilling projects are structural reservoir projects where we have several years of experience in drilling such projects. 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.* Given the volatility of commodity prices and the risks involved in drilling, we remain flexible and may 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 will allow us to be more opportunistic in cyclical price environments as well as providing more consistent financial results.

Significant Accomplishments in 2005

- *Production and reserve growth* – The fourth quarter of 2005 marked the twelfth consecutive quarter of sequential production growth. Our annual production reached 239.1 Mmcfe per day, an increase of 22% from 2004. 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 twelve quarters will be challenging to sustain, the quality of our technical teams and our sizable drilling inventory bode well for the future. A testament to this fact was the devastating hurricanes that significantly impacted our Gulf Coast and Southwest production. Despite the loss of production from these storms, we were able to continue to increase production with growth in our other core areas. Proven reserves increased 20% in 2005 to 1.4 Tcfe, marking the fourth consecutive year our proven reserves have increased.

- *Successful drilling program* – In 2005, we ended the year with 841 gross wells drilled. Competition for quality drilling and completion well services was intense in 2005, yet we were able to increase our number of wells drilled by 77% over 2004. As we continue to build our drilling inventory for the future, an ability to drill additional wells each year on a cost effective and efficient basis is important. Production was replaced by over 200% in 2005, and our overall success rate in drilling was 98%. The increased pace of drilling did not adversely impact the quality of our drilling program as the 98% success ratio in 2005 compares favorably to the 95% success ratio in 2004.

- *Continued expansion of drilling inventory and emerging plays* – To maintain our growth rate, the size of our prospect inventory must also increase. Our drilling inventory currently includes over 7,700 projects, up from approximately 5,000 at year-end 2004. Meaningful expansion of our coal bed methane projects and our shale plays occurred in 2005. We have now leased 370,000 net acres in our coal bed methane plays and 203,000 acres in our shale plays. In addition to the expansion of our emerging plays, we have added several quality veteran 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 2005. Revenue, net income, and net cash flow provided by operating activities all reached record highs, despite the effect of low-price commodity hedges put in place in prior years. All of the lower priced swaps expired at the end of 2005. The balance sheet continued to improve in 2005 as we refinanced $150 million of shorter term bank debt with a like amount of senior subordinated fixed rate 6.375% 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 and total debt was reduced slightly in 2005. Future profitability and cash flow will be enhanced through lower income taxes due to a $207.2 million net operating loss carryforward.

- *Successful acquisition completed* – In June 2005 we acquired 77 Bcfe of proven reserves in New Mexico for $116.4 million. The acquisition was producing approximately 7 Mmcfe per day when it was acquired and was producing approximately 12 Mmcfe per day at year-end. The acquisition was funded with proceeds from a public offering of 6.9 million shares for net proceeds of $109.2 million. Additional growth in production is expected in 2006 due to an active drilling program.

Plans for 2006

We have announced a $428.9 million capital budget for 2006, excluding acquisitions. The budget includes $358.4 million to drill 1,065 gross (789 net) wells and to undertake 94 gross (58 net) recompletions. Approximately 46% of the budget is attributable to the Appalachia Division, with 46% allocated to the Southwest Division and 8% to the Gulf Coast Division. Also included is $37.6 million for land, $18.5 million for seismic and $14.5 million for the expansion and enhancement of gathering systems and facilities.

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,		
	2005	2004	2003
Production			
Gas (Mmcf)	63,004	50,722	43,510
Crude oil (Mbbl)	3,031	2,512	2,023
Natural gas liquids (Mbbl)	1,012	988	401
Total (Mmcfe) [(a)]	87,263	71,726	58,053
Revenues ($000)			
Gas	$ 380,131	$ 225,738	$ 171,291
Crude oil	117,354	70,439	47,599
Natural gas liquids	27,589	19,526	7,512
Transportation and gathering	2,578	2,202	3,509
Total	527,652	317,905	229,911
Direct operating expenses [(b)]	98,148	66,812	49,317
Gross margin	$ 429,504	$ 251,093	$ 180,594
Average sales price (excluding hedging)			
Gas (per mcf)	$ 7.98	$ 5.79	$ 5.10
Crude oil (per bbl)	53.31	39.25	28.42
Natural gas liquids (per bbl)	31.52	23.73	18.75
Total (per mcfe) [(a)]	7.98	5.80	4.94
Average sales price (including hedging)			
Gas (per mcf)	$ 6.03	$ 4.45	$ 3.94
Crude oil (per bbl)	38.71	28.04	23.53
Natural gas liquids (per bbl)	27.27	19.76	18.75
Total (per mcfe) [(a)]	6.02	4.40	3.90
Operating costs (per mcfe)			
Direct	$ 0.76	$ 0.65	$ 0.63
Production and ad valorem taxes	0.36	0.29	0.22
Total	$ 1.12	$ 0.94	$ 0.85

[(a)] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcfe.
[(b)] Includes production and ad valorem taxes.

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 the financial or personnel resources of Range 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, 2006, we had 578 full-time employees, 330 of whom were field personnel. All employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. None is covered by a collective bargaining agreement. Management believes its relationship with employees is good. We regularly utilize independent consultants and contractors to perform various services, particularly in the areas of drilling, completion and field production services such as pumping, maintenance, inspection and testing, permitting and environmental assessment.

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 also 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 450 Fifth Street, N.W., Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including 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 web site 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 royalty owners and other working interest owners. Gas sales are made pursuant to a variety of contractual arrangements, including month-to-month and one-to five-year contracts. Pricing on the month-to-month and short-term contracts is based largely on the New York Mercantile Exchange, or 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 indexes. Less than 300 mcf per day is sold under long-term fixed price contracts. Most 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 term 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, 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 the information set forth in the notes to our consolidated financial statements under the caption "Major Customers" in Note 14. 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, please see the information set forth in Item 7 of this report "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. Increasing market volatility due to international political developments, overall energy supply and demand, weather conditions, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We incur gathering and transportation expenses to move our natural gas and crude oil from the wellhead and tanks to purchaser specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party transporters. In the Southwestern and Gulf Coast 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 4,800 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. See "Risk Factors – *Our business depends on oil and natural gas transportation facilities, some of which are owned by others*," in Item 1A of this report.

Governmental Regulation

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements 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, or the MMS. These leases contain relatively standardized terms and require compliance with detailed MMS regulations pursuant to the Outer Continental Shelf Lands Act, or the 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, or 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, or the EPAct 2005. Among other matters, the EPAct 2005 amends the Natural Gas Act, or 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, or 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 will 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 or the 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 2005, nor do we anticipate that such expenditures will be material in 2006.

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

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time-to-time that would alter the RCRA exemption by reclassifying certain oil and gas exploration and production wastes as "hazardous wastes" and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on 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.

ITEM 1A. RISK FACTORS

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 an extended 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. For example, in 1998 and early 1999, oil and natural gas prices declined, which contributed to the substantial losses we reported in those years. By early 2001, oil and natural gas prices reached levels above historical norms. Prices declined in the second half of 2001 but have risen steadily since mid-2002. Recent oil and natural gas prices are at historic highs, with oil prices recently reaching $70.85 per barrel and natural gas prices reaching $15.78 per mcf in some markets. 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 including technology, geopolitics, weather patterns and economics.

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

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we enter into hedging arrangements 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. For example, at December 31, 2005, we were party to swap hedging arrangements covering 6.7 Bcf and 0.1 million barrels of oil. We also had collars covering 82.8 Bcf of gas and 4.8 million barrels of oil. The derivatives' fair value was a pre-tax loss of $231.0 million. If oil and natural gas prices continue to rise, we could be subject to margin calls.

In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- Our production is less than expected;
- The counterparties to our 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.

Recently, due to the trading volatility of NYMEX gas contracts, we have 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 qualified for hedge accounting in the fourth quarter and were 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 undeveloped reserves, which comprise a significant portion of our 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. As of December 31, 2005, we continued to have production shut-in due to the effects of hurricanes Katrina and Rita primarily to pipelines and onshore facilities. While we do not currently believe there is any material long-term damage to the shut-in properties, we cannot yet predict whether impairment charges may be required due to these storms.

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 begin drilling 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. Currently, we expect substantial increases in premiums especially in the areas affected by the hurricanes and tropical storms. In addition, we expect insurers to impose 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, approximately 56% of our debt is at fixed interest rates with the remaining 44% subject to variable interest rates.

Some 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 related to offshore operations generally and in the Gulf of Mexico specifically

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 of February 20, 2006, we continued to have 1.6 Mmcfe per day of production shut-in due to the effects of hurricanes Katrina and Rita. 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.

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.

Our business depends on oil and natural gas transportation facilities, many 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 significant 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 $450 to $550 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. 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, the 7.375% and the 6.375% 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 7.375% and 6.375% 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 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, 2005, the last daily sale price of our common stock reported by the New York Stock Exchange ranged from a low of $6.29 per share to a high of $28.01 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;
- Future sales of our stock.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2005:

Division	Average Daily Production (mcfe per day)	Total Production (mcfe)	Percentage of Total Production	Total Proved Reserves (Mmcfe)	Percentage of Total Proved Reserves
Southwest	116,490	42,518,630	49%	502,578	35%
Appalachia	93,744	34,216,554	39%	838,312	60%
Gulf Coast	28,842	10,527,376	12%	65,872	5%
	239,076	87,262,560	100%	1,406,762	100%

Southwest Division

The Southwest Division conducts drilling, production and field operations in 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 interests in 1,835 net producing wells, 92% of which we operate. Our average working interest is 74%. We have approximately 550,000 gross (384,000 net) acres under lease.

Reserves increased 144.4 Bcfe, or 40%, at December 31, 2005, as compared to year-end 2004. Production was more than offset by property purchases (76 Bcfe), drilling additions (87 Bcfe) and a net favorable reserve revision. Annual production increased 14% over 2004. During 2005, the region spent $158.3 million to drill 198 (161.7 net) development wells, of which 191 (155.9 net) were productive and 1 (1 net) exploratory well which was not productive. During the year, the region achieved a 96% drilling success rate.

At December 31, 2005, the Southwest Division had a development inventory of 228 proven drilling locations and 200 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 property base in this division is located in the Appalachian basin in the northeastern United States principally in Ohio, Pennsylvania, New York, West Virginia and Virginia and to a minor extent, the Michigan basin. 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, these properties are characterized by gradual decline rates, typically producing for 10 to 35 years. We own interests in approximately 8,822 net producing wells, 74% of which we operate and 4,800 miles of gas gathering lines. Our average working interest is 74%. We have approximately 2.1 million gross (1.9 million net) acres under lease.

Reserves at December 31, 2005 increased 92.0 Bcfe, or 12%, from 2004 due to drilling additions (123.8 Bcfe) which were partially offset by a net unfavorable reserve revision and production of 34.2 Bcfe. On an annual basis, production increased 69% from 2004 due to our acquisitions in 2004 (See also Note 4 to our consolidated financial statements). During 2005, the region spent $122.6 million to drill 622 (418.7 net) development wells, of which 619 (416.7 net) were productive and 12 (9.3 net) exploratory wells, of which 10 (7.7 net) were productive. During the year, the region achieved a 99% drilling success rate. At December 31, 2005, the Appalachia Division had an inventory of 3,114 proven drilling locations and 182 proven recompletions.

Gulf Coast Division

The Gulf Coast properties are located onshore in south Texas, south 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 to the Upper Oligocene in South Louisiana at depths of 10,000 to 12,000 feet to the Sligo and Hosston formations at depths of 15,000 to 16,500 feet in the Oakvale field in Mississippi. We operate a majority of our onshore properties while third parties operate all of our offshore properties. Onshore, we have approximately 34,000 gross (17,000 net) acres under lease. Offshore properties include interests in 37 platforms in water depths ranging from 11 to 240 feet. We own interests in 30 net producing wells in this division, 39% of which we operate. Our average working interest is 22%. Our Gulf Coast Division also owns a license of a 3-D seismic database covering over 800 contiguous blocks in the shallow water of the Gulf of Mexico, primarily offshore Louisiana.

Reserves declined 5.1 Bcfe, or 7.2%, from 2004 with production partially offset by drilling additions (6.9 Bcfe). On an annual basis, production decreased 26% from 2004. During 2005, the region spent $31.2 million to drill 3 (1.1 net) development wells, of which 3 (1.1 net) were productive and 5 (1.7 net) exploratory wells, of which 3 (0.4 net) were productive. During the year, the division had a 55% drilling success rate. At December 31, 2005, the Gulf Coast Division had an inventory of 12 proven drilling locations and 37 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,				
	2005	2004	2003	2002	2001
Natural gas (Mmcf)					
Developed	724,876	580,006	344,187	320,224	276,162
Undeveloped	400,534	366,422	142,217	120,043	112,765
Total	1,125,410	946,428	486,404	440,267	388,927
Oil and NGLs (Mbbls)					
Developed	33,029	27,715	24,912	17,176	14,066
Undeveloped	13,863	10,451	8,111	5,776	6,614
Total	46,892	38,166	33,023	22,952	20,680
Total (Mmcfe) [(a)]	1,406,762	1,175,425	684,541	577,977	513,005
% Developed	65.6%	63.5%	72.1%	73.2%	70.3%

[(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 significant proved undeveloped reserves acquired in the Great Lakes and Pine Mountain acquisitions (see Note 4 to our consolidated financial statements), adding to our future drilling inventory. The Great Lakes acquisition moved our percentage of proved undeveloped reserves from 27% to 32% and the Pine Mountain acquisition increased that percentage to 37%. At year-end 2005, our proved undeveloped percentage declined from 37% to 34% as we continue to aggressively drill.

The following table sets forth summary information by division with respect to estimated proved reserves at December 31, 2005:

	Pre-tax Present Value [a]		Reserve Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 1,814,757	37%	34,134	297,773	502,578	35%
Appalachia	2,695,127	55%	11,103	771,694	838,312	60%
Gulf Coast	377,491	8%	1,655	55,943	65,872	5%
Total	$ 4,887,375	100 %	46,892	1,125,410	1,406,762	100%

[a] Future net revenues were discounted using a 10% annual discount rate and constant prices. Our pre-tax present value of $4.9 billion less discounted taxes of $1.5 billion equals our standardized measure of $3.4 billion. See also Note 16 to our consolidated financial statements.

At year-end 2005, 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, 2005, these consultants collectively reviewed approximately 84% of the 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 6%.

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

	December 31,				
	2005	2004	2003	2002	2001
Future net revenue	$ 10,429	$ 5,035	$ 2,687	$ 1,817	$ 750
Present value					
Pre-tax	4,887	2,396	1,396	965	399
After tax	3,384	1,749	1,003	500	311
Benchmark prices					
Oil price (per barrel)	$ 61.04	$ 43.33	$ 32.52	$ 31.17	$ 20.38
Gas price (per mcf)	$ 10.08	$ 6.18	$ 6.19	$ 4.75	$ 2.63
Field prices					
Oil price (per barrel)	$ 57.80	$ 40.44	$ 29.48	$ 27.52	$ 17.59
Gas price (per mcf)	$ 9.83	$ 6.05	$ 6.03	$ 4.76	$ 2.70

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.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2005. We also own royalty interests in an additional 1,656 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
	Gross	Net	Interest
Crude oil	1,937	1,637	85%
Natural gas	12,610	9,050	72%
Total	14,547	10,687	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, 2005, 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, 2005:

	Acres		Average Working
	Gross	Net	Interest
Developed	1,685,613	1,455,315	86%
Undeveloped	1,157,140	926,003	80%
Total [(a)]	2,842,753	2,381,318	84%

(a) Does not include 407,800 acres in Appalachia in which we own royalty and overriding royalty interests ranging from 1.5% to 14.5%. Also, does not include 51,000 acres in the Southwest Division attributable to a farm-in.

Undeveloped Acreage Expirations

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

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2006	118,390	84,828	9%
2007	199,640	145,689	16%
2008	168,092	138,683	15%
2009	112,193	89,340	10%
2010	76,581	67,942	7%

Drilling Results

We engage in drilling activities on properties presently owned by us and intend to drill or develop other properties we may lease or acquire in the future. 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.

	2005		2004		2003	
	Gross	Net	Gross	Net	Gros s	Net
Development wells						
Productive	813.0	573.8	436.0	368.5	322.0	180.7
Dry	10.0	7.7	16.0	12.0	16.0	11.4
Exploratory wells						
Productive	13.0	8.1	14.0	9.2	11.0	3.8
Dry	5.0	3.9	10.0	6.9	9.0	4.4
Total wells						
Productive	826.0	581.9	450.0	377.7	333.0	184.5
Dry	15.0	11.6	26.0	18.9	25.0	15.8
Total	841.0	593.5	476.0	396.6	358.0	200.3
Success ratio	98%	98%	95%	95%	93%	92%

Real Property

We lease approximately 68,500 square feet of office space primarily in Texas and Oklahoma under standard office lease arrangements that expire at various dates through April 2010. Our Appalachian Division owns a 34,500 square foot office building and various other field offices. 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 little 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; and
- 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 our business. In the opinion of management, such litigation and claims are likely to be resolved without a material adverse effect on our financial position, cash flows or results of operations. See also Note 9 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 2005.

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, or the NYSE, under the symbol "RRC." During 2005, trading volume averaged 1.3 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
2004				
First quarter	$ 8.10	$ 6.25	-	421,140
Second quarter	9.75	7.19	.0067	698,364
Third quarter	11.79	9.03	.0067	694,575
Fourth quarter	14.43	9.97	.0133	1,048,493
2005				
First quarter	$ 17.59	$ 12.34	.0133	1,072,650
Second quarter	18.62	13.50	.0133	1,334,709
Third quarter	26.33	18.01	.0133	1,203,888
Fourth quarter	28.37	20.71	.02	1,565,650

Between January 1, 2006 and February 20, 2006, the common stock traded at prices between $23.21 and $30.52 per share. The 7.375% senior subordinated notes and the 6.375% senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 20, 2006, there were approximately 1,940 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors. The bank credit facility, the 7.375% senior subordinated notes and the 6.375% 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."

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2005. Significant producing property acquisitions in 2003 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 (in thousands, except per share data).

Statement of Operations Data:

	Year Ended December 31, 2005	2004	2003	2002	2001
Revenues					
Oil and gas sales	$ 525,074	$ 315,703	$ 226,402	$ 190,954	$ 208,854
Transportation and gathering	2,578	2,202	3,509	3,495	3,435
Gain (loss) on retirement of securities	-	(39)	18,526	3,098	3,951
Mark-to-market on oil and gas derivatives	10,868	-	-	-	-
Other	(2,563)	2,841	(2,670)	(5,958)	3,375
Total revenue	535,957	320,707	245,767	191,589	219,615
Costs and expenses					
Direct operating	66,632	46,308	36,423	31,869	34,884
Production and ad valorem taxes	31,516	20,504	12,894	8,574	8,546
Exploration	29,437	21,219	13,946	11,525	5,879
General and administrative	29,432	20,634	17,818	16,217	14,622
Non-cash stock compensation	35,250	19,176	6,559	1,023	(2,410)
Interest expense and dividends on trust preferred	38,797	23,119	22,165	23,153	32,179
Depletion, depreciation and amortization	127,514	99,408	86,549	76,820	77,573
Provision for impairment	-	3,563	-	-	31,085
Total costs and expenses	358,578	253,931	196,354	169,181	202,358
Income before income taxes and accounting change	177,379	66,776	49,413	22,408	17,257
Income tax (benefit)					
Current	1,071	(245)	170	(4)	(406)
Deferred	65,297	24,790	18,319	(3,354)	-
	66,368	24,545	18,489	(3,358)	(406)
Income before cumulative effect of changes in accounting principles	111,011	42,231	30,924	25,766	17,663
Cumulative effect of changes in accounting principles, net of taxes	-	-	4,491	-	-
Net income	111,011	42,231	35,415	25,766	17,663
Gain on retirement of preferred stock		-	-	-	556
Preferred dividends	-	(5,163)	(803)	-	(10)
Net income available to common stockholders	$ 111,011	$ 37,068	$ 34,612	$ 25,766	$ 18,209
Earnings per common share:					
Net income available to common stockholders	$ 0.89	$ 0.40	$ 0.37	$ 0.32	$ 0.24
Cumulative effect of changes in accounting principles	-	-	0.05	-	-
Net income per common share	$ 0.89	$ 0.40	$ 0.42	$ 0.32	$ 0.24
Earnings per common share – assuming dilution	$ 0.86	$ 0.38	$ 0.36	$ 0.32	$ 0.24
Cumulative effect of changes in accounting principles	-	-	0.05	-	-
Net income per common share – assuming dilution	$ 0.86	$ 0.38	$ 0.41	$ 0.32	$ 0.24

	Year Ended December 31,				
	2005	2004	2003	2002	2001
Balance Sheet Data:					
Current assets [a]	$ 207,977	$ 136,336	$ 66,092	$ 50,619	$ 77,735
Current liabilities [b]	321,760	177,162	106,964	67,206	47,879
Oil and gas properties, net	1,741,182	1,402,359	723,382	564,406	533,357
Total assets	2,018,985	1,595,406	830,091	658,484	682,462
Bank debt	269,200	423,900	178,200	115,800	95,000
Non-recourse debt	-	-	70,000	76,500	98,801
Subordinated debt	346,948	196,656	109,980	90,901	108,690
Trust preferred securities	-	-	-	84,840	89,740
Stockholders' equity [c]	696,923	566,340	274,066	206,109	235,621
Weighted average dilutive shares outstanding	129,125	97,998	86,775	81,627	76,898
Cash dividends declared per common share	.0599	.0267	.0067	-	-
Cash Flow Data:					
Net cash provided from operating activities	325,745	209,249	124,680	114,472	130,572
Net cash used in investing activities	(432,377)	(624,301)	(186,838)	(103,950)	(79,163)
Net cash provided from (used in) financing activities	93,000	432,803	61,455	(12,568)	(50,641)

[a] 2005, 2004 and 2003 include deferred tax assets of $61.7 million, $26.3 million and $19.9 million, respectively. 2001 includes a hedging asset of $37.2 million.

[b] 2005, 2004, 2003 and 2002 include hedging liabilities of $160.1 million, $61.0 million, $54.3 million and $26.0 million, respectively.

[c] Stockholders' equity includes other comprehensive income (loss) of ($147.1 million), ($43.3 million), ($42.9 million), ($21.2 million) and $45.5 million in 2005, 2004, 2003, 2002 and 2001, respectively.

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 as each of our operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in Statement of Financial Accounting Standards No. 131, "Disclosure About Segments of an Enterprise and Related Information."

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 exit of larger independent producers and the 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 continue to climb in 2006. In addition, we expect drilling and service costs to increase in 2006 and for lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our natural gas and oil 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 2005, 2004 and 2003, 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.* The 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 increase in 2006 as the demand for these services continues to increase.

- *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.

- *General and Administrative Expense.* Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense.

- *Interest.* We typically finance our working capital requirements and acquisitions with borrowings under our bank credit facility, and with our longer term publically 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 2006 capital budget to be funded with internal cash flow.

- *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, or 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 and continue to recognize current tax expense as long as we are generating taxable income.

Overview of 2005 Results

During 2005, we achieved the following results:

- 22% production growth and 20% reserve growth;
- Drilled over 590 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 77 Bcfe of proved reserves.

Management's Discussion and Analysis of Income and Operations

Volumes and Price Data

	2005	2004	2003
Production:			
Crude oil (bbls)	3,031,468	2,512,434	2,023,158
NGLs (bbls)	1,011,692	988,192	400,631
Natural gas (mcfs)	63,003,600	50,722,121	43,510,180
Total (mcfe) [(a)]	87,262,560	71,725,877	58,052,911
Average daily production:			
Crude oil (bbls)	8,305	6,865	5,543
NGLs (bbls)	2,772	2,700	1,098
Natural gas (mcfs)	172,613	138,585	119,206
Total (mcfe) [(a)]	239,076	195,972	159,049
Average sales prices (excluding hedging):			
Crude oil (per bbl)	$ 53.31	$ 39.25	$ 28.42
NGLs (per bbl)	31.52	23.73	18.75
Natural gas (per mcf)	7.98	5.79	5.10
Total (per mcfe) [(a)]	7.98	5.80	4.94
Average sales prices (including hedging):			
Crude oil (per bbl)	$ 38.71	$ 28.04	$ 23.53
NGLs (per bbl)	27.27	19.76	18.75
Natural gas (per mcf)	6.03	4.45	3.94
Total (per mcfe) [(a)]	6.02	4.40	3.90

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

Overview

Our 2005 performance reflects the benefits of higher oil and gas production, higher oil and gas prices and continued focus upon our cost structure. 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, drilling service and operating cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2005 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.

Revenues increased 67% in 2005 over the same period of 2004. This increase is due to higher production and realized oil and gas prices. Our 2005 production growth is due to acquisitions completed in 2004 and to the continued success of our drilling program. Realized prices were higher by 37% in 2005 reflecting higher market prices and the expiration of lower priced oil and gas hedges. Since December 31, 2005, oil and gas prices have remained volatile, particularly the price of natural gas. On February 17, 2006, the NYMEX spot price for natural gas closed at $7.18 per Mmbtu which is significantly below the market price at the end of the year. 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 2005 to 2004

Net income increased $68.8 million, with higher average oil and gas prices and volumes as primary factors contributing to this increase. Increased revenues were partially offset by higher operating costs and higher DD&A.

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 increased 38% to $38.71 per barrel for oil and increased 36% to $6.03 per mcf for gas from 2004. The effect of our hedging program decreased realized prices $1.96 per mcfe in 2005 versus a decrease of $1.40 in 2004.

Production volume 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 $2.6 million increased $376,000 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 recent 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 offset by net IPF income of $514,000. 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. Other revenue for 2004 also includes net IPF expenses of $1.8 million.

Direct operating expense 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 were $0.76 per mcfe and increased $0.11 per mcfe from 2004 consisting of higher field level costs of $0.04 and higher workover costs of $0.07.

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.

Exploration expense increased 39% to $29.4 million due to higher seismic costs ($10.5 million) and higher personnel costs, partially offset by lower dry hole costs ($5.0 million). Exploration expense includes exploration personnel costs of $6.0 million in 2005 versus $4.4 million in 2004.

General and administrative expense for 2005 increased 43%, or $8.8 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 (See also Note 9 to our consolidated financial statements). On a per mcfe basis, general and administration expense increased from $0.29 per mcfe in 2004 to $0.34 per mcfe in 2005.

Non-cash stock compensation increased 84%, or $16.1 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. The twelve months ended December 31, 2005 also includes $5.8 million mark-to-market expense for stock appreciation rights issued 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, or 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. For 2006, based on our current reserve base, we expect our DD&A rate to average approximately $1.55 per mcfe.

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; however, we do expect to pay $1.1 million of state income taxes.

The following table presents information about our operating expenses per mcfe for 2005 and 2004.

Operating expenses per mcfe	2005	2004	Change	%
Direct operating expense	$ 0.76	$ 0.65	$ 0.11	17%
Production and ad valorem tax expense	0.36	0.29	0.07	24%
General and administration expense	0.34	0.29	0.05	17%
Interest expense	0.44	0.32	0.12	38%
Depletion, depreciation and amortization expense (excluding impairment in 2004)	1.46	1.39	0.07	5%

Comparison of 2004 to 2003

Net income increased $6.8 million, with higher average oil and gas prices and volumes as a primary factor contributing to this increase. Increased revenues were partially offset by higher operating costs and higher DD&A. The year ended 2003 included an $18.5 million gain on retirement of debt and convertible securities versus a loss of $39,000 in 2004. The year ended 2003 also included a $4.5 million favorable cumulative effect of change in accounting principle.

Average realized price received for oil and gas during 2004 was $4.40 per mcfe, up 13%, or $0.50 per mcfe, from 2003. Oil and gas revenues for 2004 reached $315.7 million and were 39% higher than 2003 due to higher oil and gas prices and a 24% increase in production. The average price received increased 19% to $28.04 per barrel for oil and increased 13% to $4.45 per mcf for gas from 2003. The effect of our hedging program decreased realized prices $1.40 per mcfe in 2004 versus a decrease of $1.04 in 2003.

Production volume increased 24% from 2003 due to our drilling program and additions from acquisitions consummated in late 2003 and 2004, primarily the Conger Field acquisition in 2003 and our purchase of the 50% of Great Lakes that we did not own in 2004. Production increased 13.7 Bcfe from 2003. Our production volumes increased 56% in our Appalachian Division, increased 30% in our Southwestern Division and declined 14% in our Gulf Coast Division.

Transportation and gathering revenue of $2.2 million declined $1.3 million from 2003. This decline is due to lower oil marketing revenues and additional gas transportation system employee expense related to the Conger Field acquisition ($1.1 million) partially offset by additional revenue related to the Great Lakes acquisition.

Gain (loss) on retirement of securities was a loss of $39,000 in 2004 versus a gain of $19.0 million in 2003. The year ended 2004 includes the purchase for cash of $2.7 million of 6% debentures. During 2003, 193,500 shares of common stock were exchanged for $880,000 of 6% debentures with a conversion expense of $465,000 recorded on the exchange. In addition, 2003 included $9.1 million of 6% debentures, $500,000 of 8.75% Notes, and $5.3 million of Trust Preferred Securities were repurchased for cash. Also in 2003, $10.2 million of cash and $50.0 million of our newly issued convertible preferred stock was exchanged for $79.5 million of Trust Preferred Securities.

Other revenue increased in 2004 to $2.8 million from a loss of $2.7 million in 2003. 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. Other revenue for 2004 also includes net IPF expenses of $1.8 million. Other revenue in 2003 includes an ineffective hedging loss of $1.2 million and net IPF expenses of $1.4 million.

Direct operating expense increased $9.9 million to $46.3 million due to increased costs from acquisitions and higher oilfield service costs. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $1.8 million of expenses associated with workovers in 2004 versus $2.7 million in 2003. On a per mcfe basis, direct operating expenses increased $0.02 per mcfe with higher field level costs offset by lower workover costs.

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $7.6 million, or 59%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes increased from $0.22 per mcfe to $0.29 per mcfe due to higher market prices.

Exploration expense increased 52% to $21.2 million due to higher dry hole costs ($8.5 million) and higher personnel costs partially offset by lower seismic purchases ($2.6 million). Exploration expense includes exploration personnel costs of $4.4 million in 2004 versus $3.3 million in 2003.

General and administrative expense for 2004 increased 16%, or $2.8 million, from 2003 due primarily to higher professional fees and additional personnel costs due to the Great Lakes acquisition. On a per mcfe basis, general and administrative expense declined from $0.31 per mcfe in 2003 to $0.29 per mcfe in 2004.

Non-cash stock compensation increased $12.6 million from 2003. 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 $6.30 per share at the end of 2003 to $13.64 per share at the end of 2004.

Interest expense for 2004 increased $1.0 million, or 4%, to $23.1 million with higher interest rates and average debt balance partially offset by a lower call premiums of $1.8 million. Interest expense for 2003 included a $2.0 million call premium on the 8.75% Notes. Average debt outstanding on the bank credit facility was $262.4 million and $104.7 million for 2004 and 2003, respectively and the average interest rates were 3.3% and 3.1%, respectively.

Depletion, depreciation and amortization, or DD&A, increased $16.4 million, or 19%, to $103.0 million due to higher production and a $3.6 million (or $0.05 per mcfe) impairment charge on an offshore property in our Gulf Coast division. The impairment was attributable to hurricane damage and related production declines. On a per mcfe basis, excluding the impairment charge on the offshore property, DD&A declined from $1.49 per mcfe to $1.39 per mcfe. For 2005, based on our current reserve base, we expect our DD&A rate to average $1.45 per mcfe.

Tax expense for 2004 increased $6.1 million, or 33%, over 2003 due to a 35% increase in income before taxes. Year-end 2004 and 2003 provide for a tax rate of 37%. Given our available net operating loss carryforward, we do not expect to pay significant cash federal income taxes.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2004.

Operating expenses per mcfe	2004	2003	Change	%
Direct operating expense	$ 0.65	$ 0.63	$ 0.02	3%
Production and ad valorem tax expense	0.29	0.22	0.07	32%
General and administration expense	0.29	0.31	(0.02)	(6%)
Interest expense	0.32	0.38	(0.06)	(16%)
Depletion, depreciation and amortization expense (excluding impairment in 2004)	1.39	1.49	(0.10)	(7%)

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

During 2005, our cash provided from operations was $325.7 million, and we spent $441.8 million on capital expenditures (including acquisitions). During this period, financing activities provided net cash of $93.0 million. Our financing activity included the sale in March 2005 of $150.0 million of 6.375% Notes that enabled us to better match the maturities of our debt with the life of our properties and decrease our interest rate volatility. In addition, in June 2005 we issued 6.9 million common shares in a public offering for net proceeds of $109.2 million. At December 31, 2005 we had $4.7 million in cash, total assets of $2.0 billion and a debt-to-capitalization ratio of 47%. Long-term debt at December 31, 2005 totaled $616.1 million, including $269.2 million of bank debt and $346.9 million of senior subordinated notes. Available borrowing capacity under the bank credit facility at December 31, 2005 was $330.8 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.

In 2004, we filed a new universal shelf registration statement with the SEC registering $500.0 million aggregate amount of common stock, preferred stock and other equity and debt securities. In December 2004, we issued 8.6 million shares of common stock under this shelf registration statement for an aggregate price of $107.8 million. In June 2005, we issued 6.9 million shares of common stock under this shelf registration for an aggregate price of $113.9 million. As of December 31, 2005, we have $278.3 million of capacity remaining under the shelf. Range qualifies as a Well-Known Seasoned Issuer.

Bank Debt

We maintain a $600.0 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 January 1, 2009. Availability under the bank credit facility is subject to a borrowing base set by the banks semi-annually and more often in certain other 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 20, 2006, the bank credit facility had a $600.0 million borrowing base of which $310.7 million was available.

Limitations on the payment of dividends and other restricted payments as defined are imposed under our bank debt, the 7.375% Notes and the 6.375% Notes. Under the bank credit facility, common and preferred dividends are permitted. The terms of both the 7.375% Notes and the 6.375% 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, 2005, approximately $432.9 million was available under the restricted payment baskets for both the 6.375% Notes and the 7.375% 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 $365.8 million was available under the bank credit facility restricted payment basket as of December 31, 2005. 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, 2005.

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, 2005, we had entered into hedging agreements covering 61.2 Bcfe, 43.7 Bcfe and 14.3 Bcfe for 2006, 2007 and 2008, respectively. The $288.2 million of cash capital expenditures for 2005, excluding acquisitions, was funded with internal cash flow. The $429.0 million capital budget for 2006, 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 2006 capital program is expected to be funded with internal cash flow.

Net cash provided from operating activities in 2005, 2004 and 2003 was $325.7 million, $209.2 million and $124.7 million, respectively. 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 and exploration expenses. In 2003, cash flow from operations increased with higher volumes and higher prices partially offset by increasing operating and exploration expenses.

Net cash used in investing activities in 2005, 2004 and 2003 was $432.4 million, $624.3 million and $186.8 million, respectively. In 2005, we spent $276.9 million in additions to oil and gas properties and $153.6 million on acquisitions. The 2004 period included $166.6 million in additions to oil and gas properties and $485.6 million of acquisitions. The 2003 period included $91.2 million in additions to oil and gas properties, and $103.9 million of acquisitions, partially offset by $10.3 million of IPF net repayments.

Net cash provided from financing activities in 2005, 2004 and 2003 was $93.0 million, $432.8 million and $61.5 million, respectively. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. 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 transaction and the remaining increase the result of funding other acquisitions. Also in 2004, we redeemed the remaining outstanding 6% Debentures for $11.6 million. During 2003, the outstanding balance under our bank credit facility increased $62.4 million primarily due to the December acquisition of producing properties in the Conger field. In 2003, total debt declined $9.9 million. During 2003, we redeemed $84.8 million of the Trust Preferred Securities and $69.3 million of the 8.75% Notes and issued $100.0 million of 7.375% Notes.

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 2005, $288.2 million of capital was expended primarily on drilling projects. Also in 2005, $153.6 million was expended on acquisitions primarily to purchase producing properties. The capital program, excluding acquisitions, was funded by net cash flow from operations and our acquisitions were funded primarily with proceeds received from our common stock offering. The 2006 capital budget of $429.0 million, excluding acquisitions, is expected to be funded by cash flow from operations. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to or below internal cash flow. To the extent capital requirements exceed internal cash flow, debt or equity may be issued to fund these requirements. 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 the 7.375% Notes and the 6.375% Notes. 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 quarter). In 2004, we paid $3.2 million in dividends to our common stockholders ($0.0067 per share in the second and third quarter and $0.0133 per share in the fourth quarter). In 2005, 2004 and 2003, we paid $2.2 million, $2.9 million and $803,000 in preferred stock dividends. As of December 31, 2004, our 5.9% convertible preferred stock was converted to common stock.

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, 2005, we do not have any capital leases nor have we entered into any material long-term contracts for drilling rigs or equipment. As of December 31, 2005, 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, 2005. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2005 reflects accrued interest payable on our bank debt of $652,000 which is payable in January 2006. We expect to make annual interest payments of $14.8 million per year on our $200.0 million of 7.375% Notes and payments of $9.6 million per year on our $150.0 million of 6.375% Notes.

The following summarizes our contractual financial obligations at December 31, 2005 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities and refinancing proceeds.

	Payment due by period				
	2006	2007 and 2008	2009 and 2010	Thereafter	Total
			(in thousands)		
Bank debt due 2009	$ -	$ -	$ 269,200 [a]	$ -	$ 269,200
7.375% senior subordinated notes due 2013	-	-	-	200,000	200,000
6.375% senior subordinated notes due 2015	-	-	-	150,000	150,000
Operating leases	2,953	3,622	1,860	-	8,435
Seismic purchase	400	400	-	-	800
Derivative obligations [b]	160,101	70,948	-	-	231,049
Asset retirement obligation liability	3,166	3,715	4,186	56,996	68,063
Total contractual obligations [c]	$166,620	$ 78,685	$ 275,246	$ 406,996	$ 927,547

[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 $14.5 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, 2005.

[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 hedging agreements to reduce the impact of oil and gas price volatility on our operations. At December 31, 2005, swaps were in place covering 6.7 Bcf of gas at prices averaging $6.60 per mcf and 0.1 million barrels of oil at prices averaging $35.00 per barrel. We also had collars covering 82.8 Bcf of gas at weighted average floor and cap prices of $6.77 to $9.43 and 4.8 million barrels of oil at weighted average floor and cap prices of $45.21 to $56.58. The hedges' 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 loss of $231.0 million at December 31, 2005. 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 $171.1 million $100.1 million and $60.4 million were realized in 2005, 2004 and 2003, respectively. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly in other income. 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, or 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 recent volatility of gas prices on the correlation between realized prices and hedge reference prices and were marked-to-market in the amount of a gain of $10.9 million.

At December 31, 2005, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural gas			
2006	Swaps	10,788 Mmbtu/day	$ 6.43
2006	Collars	113,363 Mmbtu/day	$ 6.37 - $ 8.70
2007	Swaps	7,500 Mmbtu/day	$ 6.86
2007	Collars	83,500 Mmbtu/day	$ 6.93 - $9.63
2008	Collars	30,000 Mmbtu/day	$ 7.81 - $ 11.65
Crude Oil			
2006	Swaps	400 bbl/day	$ 35.00
2006	Collars	6,864 bbl/day	$ 39.83 - $ 49.05
2007	Collars	4,800 bbl/day	$ 51.42 - $ 61.87
2008	Collars	1,500 bbl/day	$ 50.00 - $ 74.12

Interest Rates

At December 31, 2005, we had $616.1 million of debt outstanding. Of this amount, $350.0 million bears interest at a fixed rate averaging 7.0%. Bank debt totaling $269.2 million bears interest at floating rates, which averaged 5.4% at year-end 2005, excluding interest rate swaps. At December 31, 2005, we had fixed rate interest rate swap agreements on notional debt of $35.0 million. These swaps consist of two agreements at 1.8% which expire in June 2006. The 90-day LIBOR rate on December 31, 2005 was 4.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2005 would cost us approximately $2.3 million in additional annual interest, net of swaps.

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 2005 and 2004, we experienced an overall increase in drilling and service costs compared to 2003, especially with regard to steel products. We expect further increases in these costs for 2006.

The following table indicates the average oil and gas prices received over the last five years and quarterly for 2005, 2004 and 2003. 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)		
	Oil (Per bbl)	Natural Gas (Per mcf)	Equivalent Mcf (Per mcfe)
Annual			
2005	$ 53.31	$ 7.98	$ 7.98
2004	39.25	5.79	5.80
2003	28.42	5.10	4.94
2002	23.34	3.02	3.16
2001	23.34	3.91	3.87
Quarterly			
2005			
First	$ 47.09	$ 5.97	$ 6.24
Second	48.79	6.42	6.65
Third	52.21	6.79	7.05
Fourth	56.39	11.30	10.57
2004			
First	$ 32.15	$ 5.21	$ 5.10
Second	35.87	5.56	5.49
Third	40.99	5.59	5.70
Fourth	45.85	6.66	6.72
2003			
First	$ 31.44	$ 6.08	$ 5.79
Second	26.71	5.15	4.90
Third	27.42	4.75	4.64
Fourth	28.27	4.51	4.49

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. Actual results could differ from the estimates and assumptions used.

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.

Property, Plant and Equipment

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. In addition, because substantially all of our proved reserves are pledged as collateral for our bank credit facility, our estimates of proved reserves are reviewed twice annually by independent engineers on behalf of each of the sixteen banks participating in our bank credit facility. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to review our estimates of proved reserves.

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 2005, 2004 and 2003.

Audited [(a)]		
2005	2004	2003
84%	88%	87%

(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 $28.6 million, $14.8 million and $12.2 million in 2005, 2004 and 2003, respectively.

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 16, "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.

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." 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 OCI, and then reclassified to earnings, in oil and gas revenue, when the 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 qualified for hedge accounting due to the volatility of gas prices and their effect on our basis differentials and were 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. We also have two interest rate swap agreements to help protect against the volatility of variable interest rates under our bank credit facility.

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.

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, or ARO liability, 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 DD&A, 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 (loss) has not yet been earned. At year-end 2004, deferred tax liabilities exceeded deferred tax assets by $91.4 million with $26.0 million of deferred tax assets related to unrealized deferred hedging losses included in OCI. 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. Based on our expectations regarding future profitability and market prices for oil and gas, the unrealized hedging losses are expected to be offset in the future by higher realization on our production and no year-end 2005 valuation allowance was deemed necessary.

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 December 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statements No. 123 (revised 2004) "Share-Based Payment," or SFAS 123(R), which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. SFAS 123(R) supersedes APB opinion No. 25, Accounting for Stock Issued to employees, and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in SFAS 123(R) is similar to the approach described in Statement 123. However, SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statements based on their fair values rather than pro forma footnote disclosure.

SFAS 123(R) permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123(R) for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123(R). Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS 123. We currently anticipate we will adopt the provisions of SFAS 123(R) using the modified prospective method on January 1, 2006.

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options and stock appreciation rights granted. While SFAS 123(R) permits entities to continue to use such a model, the standard also permits the use of a "lattice" binomial model. We currently anticipate we will continue using the standard option pricing model (i.e. Black Sholes) upon adoption of SFAS 123(R).

The adoption of SFAS 123(R) will have a significant impact on our results of operations, although it will have no impact on our overall financial position. The impact of adoption of Statement 123(R) cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted Statement 123(R) in prior periods, the impact of that standard would have approximated the impact of Statement 123 as described in the disclosure of pro forma net income and earnings per share as shown in Note 2 "Stock Based Compensation" in our consolidated financial statements. Statement 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), there was no impact on our net operating cash flows in 2005, 2004 or 2003, respectively, as we were not able to recognize a cash benefit due to our net operating loss carryforward tax position.

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statements No. 3" or SFAS 154. SFAS 154 provides guidance on the accounting for a reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to SFAS 154. The provisions of SFAS 154 shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

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 hedging arrangements with respect to our oil and gas production. Hedging is intended to reduce the impact of oil and gas price fluctuations. Certain of our hedges are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our hedging program also includes collars which assume a minimum floor price and a predetermined ceiling price. 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, or OCI. 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.

As of December 31, 2005, we had oil and gas swaps in place covering 6.7 billion Bcf of gas and 0.1 million barrels of oil. We also had collars covering 82.8 Bcf of gas and 4.8 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, 2005, approximated a net pre-tax loss of $231.0 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 2005, 2004 and 2003, pre-tax losses were realized in the amount of $171.1 million, $100.1 million and $60.4 million, respectively, relating to our hedges. Losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues in our consolidated statement of operations. The ineffective portion of hedges recorded was a loss of $3.4 million in 2005, a gain of $712,000 in 2004 and a loss of $1.2 million in 2003. 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 were marked to market as a gain of $10.9 million.

At December 31, 2005, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural gas			
2006	Swaps	10,788 Mmbtu/day	$ 6.43
2006	Collars	113,363 Mmbtu/day	$ 6.37 - $ 8.70
2007	Swaps	7,500 Mmbtu/day	$ 6.86
2007	Collars	83,500 Mmbtu/day	$ 6.93 - $9.63
2008	Collars	30,000 Mmbtu/day	$ 7.81 - $ 11.65
Crude Oil			
2006	Swaps	400 bbl/day	$ 35.00
2006	Collars	6,864 bbl/day	$ 39.83 - $ 49.05
2007	Collars	4,800 bbl/day	$ 51.42 - $ 61.87
2008	Collars	1,500 bbl/day	$ 50.00 - $ 74.12

In 2005, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $70.0 million. If oil and gas futures prices at December 31, 2005 had declined by 10%, the unrealized hedging loss at that date would have decreased $118.2 million.

Interest Rate Risk

At December 31, 2005, we had $616.1 million of debt outstanding. Of this amount, $350.0 million bears interest at a fixed rate averaging 7.0%. Bank debt totaling $269.2 million bears interest at floating rates, excluding interest rate swaps, which averaged 5.4% on that date. At December 31, 2005, we had fixed rate interest rate swap agreements totaling $35.0 million. These swaps consist of two agreements at 1.8% which expire in June 2006. On December 31, 2005, the 90-day LIBOR rate was 4.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2005 would cost us approximately $2.3 million in additional annual interest rates, net of swaps.

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, 2005. 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 2005 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 2005 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.

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 2005 annual stockholders' meeting. Officers are appointed by our board of directors.

	Age	Office Held Since	Position
Charles L. Blackburn	78	2003	Director, Chairman of the Board
Anthony V. Dub	56	1995	Director
V. Richard Eales	69	2001	Director
Allen Finkelson	59	1994	Director
Jonathan S. Linker	57	2002	Director
Kevin S. McCarthy	46	2005	Director
John H. Pinkerton	51	1990	Director, President, Chief Executive Officer
Jeffrey L. Ventura	48	2003	Director, Executive Vice President – Chief Operating Officer
Steven L. Grose	57	2005	Senior Vice President – Appalachia
Roger S. Manny	48	2003	Senior Vice President and Chief Financial Officer
Chad L. Stephens	50	1990	Senior Vice President – Corporate Development
Rodney L. Waller	56	1999	Senior Vice President, Chief Compliance Officer and Corporate Secretary
Mark D. Whitley	54	2005	Senior Vice President – Permian Business Unit and Engineering Technology

Charles L. Blackburn was elected as a director in April 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 27 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 began working with First Reserve Corporation in 1988 and was a Managing Director of the firm from 1996 until July 2001. Mr. Linker is currently President of Houston Energy Advisors LLC, a registered 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 and Kayne Anderson Energy Total Return Fund, Inc. which are each NYSE listed closed-end investment companies. Mr. McCarthy joined Kayne Anderson Capital Advisors as a Senior Managing Director in June 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.

Steven L. Grose, Senior Vice President – Appalachia, joined Range in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. from 1971 until 1978. Upon the formation of Great Lakes Energy Partners L.L.C. 1999, Mr. Grose was placed in charge of all operations of the joint venture. 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 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 Worchester Polytechnic Institute and a Master's degree in Chemical Engineering from the University of Kentucky.

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.

Board of Directors Committees

See "Governance of the Company" in the Range Resources Corporation Proxy Statement for the Annual Meeting of Stockholders' of Range Resources to be held May 24, 2006 which is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

See "Section 16(a) Beneficial Ownership Reporting Compliance" in the Range Resources Corporate Proxy Statement for the Annual Meeting of Stockholders' of Range Resources to be held May 24, 2006 which is incorporated herein by reference.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

The information required by Item 11 of Form 10-K is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for the 2006 Annual Meeting of Stockholders to be held May 24, 2006.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by Item 12 of Form 10-K is incorporated herein by reference to such information as set forth in our definitive proxy statement for the 2006 Annual Meeting of Stockholders to be held on May 24, 2006.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Item 14 of Form 10-K is incorporated herein by reference to such information as set forth in our definitive proxy statement for the 2006 Annual Meeting of Stockholders to be held on May 24, 2006.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report

1. Financial Statements:

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.

2. Exhibits:

(a) See Index of Exhibits on page F-38 for a description of the exhibits filed as a part of this report.

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.

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.

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 22, 2006

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 capacities and on the dates indicated.

/s/ Charles L. Blackburn Charles L. Blackburn	Chairman of the Board	February 22, 2006
/s/ John H. Pinkerton John H. Pinkerton	President, Chief Executive Officer and Director	February 22, 2006
/s/ Jeffrey L. Ventura Jeffrey L. Ventura	Executive Vice President and Director	February 22, 2006
/s/ Roger S. Manny Roger S. Manny	Chief Financial and Accounting Officer	February 22, 2006
/s/ Anthony V. Dub Anthony V. Dub	Director	February 22, 2006
/s/ V. Richard Eales V. Richard Eales	Director	February 22, 2006
/s/ Allen Finkelson Allen Finkelson	Director	February 22, 2006
/s/ Jonathan S. Linker Jonathan S. Linker	Director	February 22, 2006
/s/ Kevin S. McCarthy Kevin S. McCarthy	Director	February 22, 2006

RANGE RESOURCES CORPORATION

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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 Rules 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, 2005. 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, 2005, 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, 2005, 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
John H. Pinkerton
President and Chief Executive Officer

By: /s/ Roger S. Manny
Roger S. Manny
Senior Vice President and Chief Financial Officer

Fort Worth, Texas
February 22, 2006

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

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 and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, 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 and subsidiaries maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Range Resources Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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 and subsidiaries as of December 31, 2005 and 2004 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, 2005 and our report dated February 21, 2006 expressed an unqualified opinion thereon.

Ernst & Young LLP

Fort Worth, Texas
February 21, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation and subsidiaries (the "Company") as of December 31, 2005 and 2004, 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, 2005. 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 and subsidiaries at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

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, 2005, 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 21, 2006 expressed an unqualified opinion thereon.

Ernst & Young LLP

Fort Worth, Texas
February 21, 2006

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEET
(In thousands)

	December 31, 2005	December 31, 2004
Assets		
Current assets		
Cash and equivalents	$ 4,750	$ 18,382
Accounts receivable, less allowance for doubtful accounts of $624 and $967	128,532	81,942
Unrealized derivative gain	425	534
Deferred tax asset	61,677	26,310
Inventory and other	12,593	9,168
Total current assets	207,977	136,336
Unrealized derivative gain	-	206
Oil and gas properties, successful efforts method	2,548,090	2,097,026
Accumulated depletion and depreciation	(806,908)	(694,667)
	1,741,182	1,402,359
Transportation and field assets	65,210	59,423
Accumulated depreciation and amortization	(25,966)	(22,141)
	39,244	37,282
Other assets	30,582	19,223
Total assets	$ 2,018,985	$ 1,595,406
Liabilities		
Current liabilities		
Accounts payable	$ 119,907	$ 78,723
Asset retirement obligations	3,166	6,822
Accrued liabilities	28,372	23,292
Accrued interest	10,214	7,320
Unrealized derivative loss	160,101	61,005
Total current liabilities	321,760	177,162
Bank debt	269,200	423,900
Subordinated notes	346,948	196,656
Deferred tax, net	174,817	117,713
Unrealized derivative loss	70,948	10,926
Deferred compensation liability	73,492	38,799
Asset retirement obligations	64,897	63,905
Long-term capital lease obligation	-	5
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, 129,913,046 and 121,829,027 issued, respectively	1,299	1,218
Common stock held in treasury – 5,826 at December 31, 2005	(81)	-
Capital in excess of par value	845,519	707,463
Retained earnings (deficit)	13,800	(89,597)
Common stock held by employee benefit trust, 1,971,605 and 2,162,626 shares, respectively, at cost	(11,852)	(8,186)
Deferred compensation	(4,635)	(1,257)
Accumulated other comprehensive income (loss)	(147,127)	(43,301)
Total stockholders' equity	696,923	566,340
Total liabilities and stockholders' equity	$ 2,018,985	$ 1,595,406

See accompanying notes.

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Revenues			
Oil and gas sales	$ 525,074	$ 315,703	$ 226,402
Transportation and gathering	2,578	2,202	3,509
Gain (loss) on retirement of securities	-	(39)	18,526
Mark-to-market on oil and gas derivatives	10,868	-	-
Other	(2,563)	2,841	(2,670)
Total revenue	535,957	320,707	245,767
Costs and expenses			
Direct operating	66,632	46,308	36,423
Production and ad valorem taxes	31,516	20,504	12,894
Exploration	29,437	21,219	13,946
General and administrative	29,432	20,634	17,818
Non-cash stock compensation	35,250	19,176	6,559
Interest expense and dividends on trust preferred	38,797	23,119	22,165
Depletion, depreciation and amortization	127,514	102,971	86,549
Total costs and expenses	358,578	253,931	196,354
Income before income taxes and accounting change	177,379	66,776	49,413
Income tax (benefit)			
Current	1,071	(245)	170
Deferred	65,297	24,790	18,319
	66,368	24,545	18,489
Income before cumulative effect of changes in accounting principles	111,011	42,231	30,924
Cumulative effect of changes in accounting principles, net of taxes	-	-	4,491
Net income	111,011	42,231	35,415
Preferred dividends	-	(5,163)	(803)
Net income available to common stockholders	$ 111,011	$ 37,068	$ 34,612
Earnings per common share:			
Net income available to common stockholders	$ 0.89	$ 0.40	$ 0.37
Cumulative effect of changes in accounting principles	-	-	0.05
Net income per common share	$ 0.89	$ 0.40	$ 0.42
Earnings per common share – assuming dilution	$ 0.86	$ 0.38	$ 0.36
Cumulative effect of changes in accounting principles	-	-	0.05
Net income per common share – assuming dilution	$ 0.86	$ 0.38	$ 0.41

See accompanying notes.

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

	Year Ended December 31,		
	2005	**2004**	**2003**
Increase (decrease) in cash and equivalents			
Operating activities:			
Net income	$ 111,011	$ 42,231	$ 35,415
Adjustments to reconcile net cash provided from operating activities:			
Deferred income tax expense	65,297	24,790	18,319
Cumulative effect of changes in accounting principles, net	-	-	(4,491)
Depletion, depreciation and amortization	127,514	102,971	86,549
Exploration dry hole costs	7,045	9,493	3,576
Mark-to-market on oil and gas derivatives (gains) losses	(10,868)	-	-
Unrealized derivative (gains) losses	3,505	(1,793)	679
Allowance for bad debts	675	1,762	2,138
Amortization of deferred issuance costs and discount	1,662	1,071	1,207
Debt conversion and extinguishment expense	-	-	465
Deferred compensation adjustments	37,391	20,667	6,867
(Gain) loss on retirement of securities	-	34	(19,634)
(Gain) loss on sale of assets and other	(512)	(3,143)	217
Changes in working capital:			
Accounts receivable	(44,533)	(25,898)	(11,530)
Inventory and other	(3,452)	(6,080)	501
Accounts payable	27,472	34,746	2,982
Accrued liabilities and other	3,538	8,398	1,420
Net cash provided from operating activities	325,745	209,249	124,680
Investing activities:			
Additions to oil and gas properties	(276,907)	(166,560)	(91,188)
Additions to field service assets	(11,310)	(4,237)	(2,618)
Acquisitions (net of cash acquired)	(153,600)	(485,564)	(103,869)
IPF net repayments	6,008	5,938	10,308
Disposal of assets	3,432	26,122	529
Net cash used in investing activities	(432,377)	(624,301)	(186,838)
Financing activities:			
Borrowings on credit facilities	299,000	634,578	318,700
Repayments on credit facilities	(453,700)	(528,878)	(262,800)
Issuance of subordinated notes	150,000	98,125	98,272
Treasury stock purchases	(2,808)	-	-
Dividends paid - common stock	(7,614)	(3,219)	-
- preferred stock	(2,213)	(2,950)	(803)
Debt issuance costs	(4,119)	(3,630)	(2,183)
Issuance of common stock	114,470	250,460	2,777
Other debt repayments	(16)	(11,683)	(92,508)
Net cash provided from financing activities	93,000	432,803	61,455
Net increase (decrease) in cash and equivalents	(13,632)	17,751	(703)
Cash and equivalents at beginning of year	18,382	631	1,334
Cash and equivalents at end of year	$ 4,750	$ 18,382	$ 631

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(In thousands)

	Preferred stock		Common stock								
	Shares	Par Value	Shares	Par Value	Treasury Common Stock	Capital in excess of par value	Retained earnings (deficit)	Stock held by employee benefit trust	Deferred compensation	Accumulated other comprehensive loss	Total
Balance December 31, 2002	**-**	**$ -**	**82,488**	**$ 825**	**-**	**$ 390,807**	**$ (158,059)**	**$ (6,188)**	**$ (125)**	**$ (21,151)**	**$ 206,109**
Issuance of preferred stock	1,000	50,000	-	-	-	-	-	-	-	-	**50,000**
Preferred dividends ($0.80 per share)	-	-	-	-	-	-	(803)	-	-	-	**(803)**
Issuance of common stock	-	-	1,934	19	-	7,205	-	(2,253)	(731)	-	**4,240**
Common dividends ($0.0067 per share)	-	-	-	-	-	-	(564)	-	-	-	**(564)**
Conversion of securities	-	-	194	2	-	1,368	-	-	-	-	**1,370**
Other comprehensive loss	-	-	-	-	-	-	-	-	-	(21,701)	**(21,701)**
Net income	-	-	-	-	-	-	35,415	-	-	-	**35,415**
Balance December 31, 2003	1,000	50,000	84,616	846	-	399,380	(124,011)	(8,441)	(856)	(42,852)	**274,066**
Preferred dividends ($5.16 per share)	-	-	-	-	-	-	(5,163)	-	-	-	**(5,163)**
Issuance of common stock	-	-	28,390	284	-	258,171	-	255	(401)	-	**258,309**
Common dividends ($0.0267 per share)	-	-	-	-	-	-	(2,654)	-	-	-	**(2,654)**
Conversion of securities	(1,000)	(50,000)	8,823	88	-	49,912	-	-	-	-	**-**
Other comprehensive loss	-	-	-	-	-	-	-	-	-	(449)	**(449)**
Net income	-	-	-	-	-	-	42,231	-	-	-	**42,231**
Balance December 31, 2004	-	-	121,829	1,218	-	707,463	(89,597)	(8,186)	(1,257)	(43,301)	**566,340**
Issuance of common stock	-	-	8,084	81	-	138,056	-	(3,666)	(3,378)	-	**131,093**
Common dividends ($0.0599 per share)	-	-	-	-	-	-	(7,614)	-	-	-	**(7,614)**
Treasury stock purchases	-	-	-	-	(2,808)	-	-	-	-	-	**(2,808)**
Treasury stock issuances	-	-	-	-	2,727	-	-	-	-	-	**2,727**
Other comprehensive loss	-	-	-	-	-	-	-	-	-	(103,826)	**(103,826)**
Net income	-	-	-	-	-	-	111,011	-	-	-	**111,011**
Balance December 31, 2005	**-**	**$ -**	**129,913**	**$ 1,299**	**$ (81)**	**$ 845,519**	**$ 13,800**	**$ (11,852)**	**$ (4,635)**	**$ (147,127)**	**$ 696,923**

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2005	**2004**	**2003**
Net income	$ 111,011	$ 42,231	$ 35,415
Net deferred hedge gains (losses), net of tax:			
Contract settlements reclassified to income	101,209	63,633	39,640
Change in unrealized deferred hedging losses	(206,348)	(64,477)	(61,531)
Change in unrealized gains (losses) on securities held by deferred compensation plan, net of taxes	1,313	395	190
Comprehensive income	$ 7,185	$ 41,782	$ 13,714

See accompanying notes.

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 acquisition 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 Range, our wholly-owned subsidiaries and a 50% pro rata share of the income and expenses of Great Lakes through June 23, 2004. The statement of operations for the twelve months ended December 31, 2004 includes 50% of the revenues and expenses of Great Lakes up to June 23, 2004 and 100% thereafter. All significant 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. Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluation for impairment of proved and unproved oil and gas properties is subject to numerous uncertainties including estimates of future recoverable reserves and commodity price outlook. Other estimates which may significantly impact our financial statements include asset retirement obligations, deferred income tax assets and fair value of derivatives.

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 exercise of stock options 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, or the FASB, Statement of Financial Accounting Standards No. 131, "Disclosure About Segments of an Enterprise and Related Information," or SFAS 131, 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 each of our core operating areas has similar economic characteristics and each meets the criteria for aggregation as defined in SFAS 131. All of our operations involve the exploration, development and production of natural gas and oil and all of our operations are located in the United States. 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 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 $623,800 and $967,000 at December 31, 2005 and 2004, respectively.

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, 2005 and December 31, 2004 were not significant. At December 31, 2005, we had recorded a net liability of $854,000 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. The December 2004 balance sheet includes $17.3 million of cash in an escrow account. These funds were proceeds received from the sale of oil and gas properties which were held in escrow to be used to purchase similar assets. In the second quarter of 2005, these escrow proceeds less transaction expenses were applied towards the bank credit facility.

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 rates were $1.46, $1.44 and $1.49 per mcfe in 2005, 2004 and 2003, respectively. Depletion is provided on the unit-of-production method. Unproved properties had a net book value of $28.6 million, $14.8 million and $12.2 million at December 31, 2005, 2004 and 2003, respectively. 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 and abandonment is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans 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.

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 $6.4 million, $4.7 million and $3.0 million in 2005, 2004 and 2003, respectively.

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 securities. When a security is retired prior to maturity, related unamortized costs are expensed. Other assets at December 31, 2005 include $7.9 million unamortized debt issuance costs, $21.8 million of marketable securities held in the deferred compensation plan and $904,000 of long-term deposits. Other assets also includes an IPF receivable of $2.6 million offset by an IPF allowance of $2.6 million.

Stock-based Compensation

The 2005 Equity Based Compensation Plan, or 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, or 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 the May 18, 2005, 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 generally vest over a three year period and expire five years from the date they are granted. Similar to stock options, stock appreciation rights, or 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 to limit 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. Unearned compensation is charged to equity when restricted stock is granted. Compensation expense is recognized over the balance of the vesting period or the period for services to be rendered.

We apply the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees, and related interpretations,” in accounting for our stock options. As such, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeds the exercise price. SFAS No. 123, “Accounting for Stock-Based Compensation,” or SFAS 123, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS 123, we have elected to continue to apply the intrinsic value-based method of accounting described above, and we have adopted the disclosure requirements of SFAS 123, which was amended by SFAS No. 148, “Accounting for Stock-Based Compensation-Transition and Disclosures.” See also “Accounting Pronouncements Not Yet Adopted” below.

We have adopted the disclosure-only provisions of SFAS 123. Accordingly, no compensation cost has been recognized for our stock options because the exercise prices of the stock options equals the market prices of the underlying stock on the date of grant. However, compensation expense of $5.8 million has been recognized for our SARs granted during the year. If compensation cost had been determined based on the fair value at the grant date for awards in 2005, 2004 and 2003 consistent with the provisions of SFAS 123, our net income and earnings per share would have been reduced to the pro forma amounts indicated below:

	Year Ended December 31,		
	2005	2004	2003
	(in thousands, except per share data)		
Net income as reported	$ 111,011	$ 42,231	$ 35,415
Add: Total stock-based employee compensation expense included in net income, net of tax	23,556	13,020	4,326
Deduct: Total stock-based employee compensation expense determined under fair value based method, net of tax	(29,235)	(17,114)	(6,365)
Pro forma net income	$ 105,332	$ 38,137	$ 33,376
Earnings per share:			
Basic-as reported	$ 0.89	$ 0.40	$ 0.42
Basic-pro forma	0.85	0.35	0.40
Diluted-as reported	0.86	0.38	0.41
Diluted-pro forma	0.82	0.34	0.38

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 assumption used for 2005, 2004 and 2003, respectively: fair value of $8.48, $4.52 and $2.61 per share; expected dividend per share of $0.08, $0.04 and $0.00; expected volatility factors of 54%, 67% and 73%; risk-free interest rates of 4.1%, 3.5% and 3.2%, 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, or 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 $236.9 million loss recorded in OCI at December 31, 2005, $171.5 million is expected to be reclassed to income in 2006, if prices remain constant at their December 31, 2005 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 recent volatility of gas prices on the correlation between realized prices and hedge reference prices. As a result, we recognized $10.9 million of gain in the fourth quarter because oil and gas derivatives in our Southwestern Division no longer qualified for hedge accounting. These derivative positions will continue to be marked-to-market going forward into 2006. This may result in more volatility in our income in future periods. We have also entered into swap agreements to reduce the risk of changing interest rates. These interest rate swaps are not designated as hedges and are marked to market each month as a component of interest expense.

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.

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS 130, "Reporting Comprehensive Income" which establishes standards for reporting comprehensive income. Comprehensive income, or OCI, 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, 2005, we had a $236.9 million pre-tax loss in OCI relating to unrealized commodity hedges. We also had a pre-tax gain of $2.9 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, 2005, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2002	$ (32,539)	$ 11,388	$ (21,151)
Contract settlements reclassified to income	60,427	(20,787)	39,640
Change in unrealized deferred hedging losses	(95,657)	34,126	(61,531)
Change in unrealized gains (losses) on securities held by deferred compensation plan	297	(107)	190
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)
Change in unrealized gains (losses) on securities held by deferred compensation plan	2,049	(736)	1,313
Accumulated other comprehensive loss at December 31, 2005	$ (234,363)	$ 87,236	$(147,127)

Reclassifications

Certain reclassifications of prior years' data have been made to conform with our current year classification.

Accounting Pronouncements Implemented

In April 2005, the FASB issued Staff Position No. FAS 19-1, "Accounting for Suspended Well Costs," or FSP 19-1. FSP 19-1 amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," or SFAS 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the wells has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. FSP 19-1 also amends SFAS 19 to require enhanced disclosures of suspended exploratory well costs in the notes to the financial statements for annual and interim periods when there has been a significant change from the previous disclosure. The guidance in FSP 19-1 was effective for the first reporting period beginning after April 4, 2005. Accordingly, we adopted the new requirements on July 1, 2005 and have included the required disclosures in footnote 3. The adoption of FSP 19-1 did not impact our consolidated financial position or results of operations.

Accounting Pronouncements Not Yet Adopted

In December 2004, the Financial Accounting Standards Board, or FASB, issued FASB Statement No. 123 (revised 2004) "Share-Based Payment," or SFAS 123(R), which is a revision of FASB Statement No. 123, Accounting for Stock-Based Compensation. SFAS 123(R) supersedes APB opinion No. 25, Accounting for Stock Issued to employees, and amends FASB Statement No. 95, Statement of Cash Flows. Generally, the approach in SFAS 123(R) is similar to the approach described in Statement 123. However, SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values rather than pro forma footnote disclosure.

SFAS 123(R) permits companies to adopt its requirements using either a "modified prospective" method, or a "modified retrospective" method. Under the "modified prospective" method, compensation costs is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123(R) for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123(R). Under the "modified retrospective" method, the requirements are the same as under the "modified prospective" method, but also permits entities to restate financial statements of previous periods based on pro forma disclosures made in accordance with SFAS 123. We have elected to adopt the provisions of SFAS 123(R) using modified prospective method on January 1, 2006.

We currently utilize a standard option pricing model called Black-Scholes to measure the fair value of stock options and stock appreciation rights granted. While SFAS 123(R) permits entities to continue to use such a model, the standard also permits the use of a "lattice" binomial model. We currently anticipate we will continue using Black Scholes upon adoption of SFAS 123(R).

The adoption of SFAS 123(R) will have a significant impact on our consolidated statement of operations, although it will have no impact on our overall financial position. The impact of adoption of Statement 123(R) cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted Statement 123(R) in prior periods, the impact of that standard would have approximated the impact of Statement 123 as described in the disclosure of pro forma net income and earnings per share above. SFAS 123(R) also requires the benefits of tax deductions in excess of recognized compensation cost to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend on when employees exercise stock options, among other things), there was no impact on our net operating cash flows in 2005, 2004 or 2003, respectively, as we were not able to recognize a cash benefit due to our net operating loss carryforward tax position.

In June 2005, the Compensation Committee of the Board of Directors approved the acceleration of certain unvested options. Certain unvested options with vesting dates between January 1, 2006 and April 1, 2006 were accelerated so they would vest on December 31, 2005, representing an average acceleration of 46 days. There were approximately 1.1 million options held by management and non-management employees affected by the acceleration which was undertaken primarily to reduce future stock-based compensation under SFAS 123(R).

In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections – a replacement of APB Opinion No. 20 and FASB Statements No. 3," or SFAS 154, which provides guidance on the accounting for a reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to SFAS 154. The provisions of SFAS 154 shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

(3) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the twelve months ended December 31, 2005, 2004 and 2003 (in thousands):

	2005	2004	2003
Balance at beginning of period	$ 7,332	$ 2,043	$ 4
Additions to capitalized exploratory well costs pending the determination of proved reserves	26,915	4,767	2,039
Additions due to purchase of Great Lakes	-	2,012	-
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(8,614)	(784)	-
Capitalized exploratory well costs charged to expense	(293)	(706)	-
Balance at end of period	25,340	7,332	2,043
Less exploratory well costs that have been capitalized for a period of one year or less	(21,589)	(6,124)	(2,039)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 3,751	$ 1,208	$ 4
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	-

As of December 31, 2005, of the $3.8 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. The $25.3 million of capitalized exploratory well costs at December 31, 2005 was incurred in 2005 ($21.6 million), in 2004 ($3.5 million) and in 2003 ($200,000).

(4) ACQUISITIONS AND DISPOSITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our statement of operations from the effective 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 $173.5 million, $648.2 million and $100.9 million, during the years ended December 31, 2005, 2004 and 2003, respectively. These purchases included $152.8 million, $619.0 million and $90.7 million for proved oil and gas reserves, respectively; the remainder represents unproved acreage purchases. As part of our acquisitions for 2004 and 2003, we allocated $15.5 million and $4.6 million to gathering facilities acquired in the transactions. See also Note 16 – Costs Incurred for Property Acquisition, Exploration and Development.

On December 10, 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. The following table summarizes the final allocation of the purchase price to assets acquired and liabilities assumed at the date of acquisition (in thousands):

	Pine Mountain
Purchase price:	
Cash paid (including transaction costs)	$ 223,917
Total	$ 223,917
Allocation of purchase price:	
Working capital	5,960
Oil and gas properties	297,265
Field assets and gathering system assets	1,046
Deferred income taxes, net	(79,860)
Asset retirement obligations and other	(494)
Total	$ 223,917

On June 23, 2004, we purchased the 50% of Great Lakes we did not previously own for $200.0 million 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 table summarizes the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of acquisition (in thousands):

	Great Lakes
Purchase price:	
Cash paid (including transaction costs)	$ 228,824
Total	$ 228,824
Allocation of purchase price:	
Working capital	5,062
Oil and gas properties	296,160
Field assets and gathering system assets	14,429
Other non-current assets	866
Asset retirement obligations and other	(17,693)
Long-term debt	(70,000)
Total	$ 228,824

The following unaudited pro forma data include the results of operations of the above 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).

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

In June 2005, we purchased Permian Basin properties for $116.4 million. As a preliminary allocation of purchase price, we have recorded $136.8 million to oil and gas properties $133,000 of working capital, $20.5 million of deferred tax liability and $119,000 of additional asset retirement obligations. The acquisition was partially funded with the proceeds from a public offering of 4.6 million common shares for $109.2 million. No pro forma information has been provided as the acquisition was not considered significant.

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(5) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2005 and 2004 is as follows (in thousands):

	2005	2004
Asset retirement obligation - beginning of period	$ 70,727	$ 51,844
Liabilities incurred	3,813	20,237
Liabilities settled	(6,126)	(7,175)
Accretion expense	5,072	4,539
Change in estimate	(5,423)	1,282
Total	68,063	70,727
Less current portion	(3,166)	(6,822)
Asset retirement obligation - end of period	$ 64,897	$ 63,905

(6) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31, 2005	2004	2003
	(in thousands)		
Net cash provided from operating activities included:			
Income taxes paid to taxing authorities	$ 615	$ 150	$ 110
Interest paid	34,148	19,216	21,579
Non-cash investing and financing activities included:			
Common stock issued:			
Under benefit plans	$ 3,180	$ 2,122	$ 3,672
Exchanged for fixed income securities	-	-	1,370
Preferred stock issued	-	-	50,000
Preferred stock converted to common stock	-	(50,000)	-
Asset retirement costs capitalized, excluding acquisitions[a]	(1,730)	3,994	4,597

[a] For information regarding purchase price allocations of businesses acquired see Note 4.

(7) INDEBTEDNESS

We had the following debt outstanding as of the dates shown (interest rates, excluding the impact of interest rate swaps, at December 31, 2005 are shown parenthetically). No interest was capitalized during 2005, 2004, and 2003 (in thousands):

	December 31, 2005	2004
Bank debt (5.4%)	$ 269,200	$ 423,900
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of $3.1 million and $3.3 million discount, respectively	196,948	196,656
6.375% Senior Subordinated Notes due 2015	150,000	-
Total debt	$ 616,148	$ 620,556

Bank Debt

In June 2004, we entered into an amended and restated $600.0 million revolving bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and to certain unscheduled redeterminations. As of December 31, 2005, the outstanding balance under the bank credit facility was $269.2 million and there was $330.8 million of borrowing capacity available. The loan matures on January 1, 2009. 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 its 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 4.5% and 3.2% for the years ended December 31, 2005 and 2004, respectively. A commitment fee is paid on the undrawn balance based on an annual rate of 0.25% to 0.50%. At December, 31, 2005, the commitment fee was 0.25% and the interest rate margin was 1.0%. At February 20, 2006, the interest rate (including applicable margin) was 5.6%.

7.375% Senior Subordinated Notes due 2013

In July 2003, we issued $100.0 million aggregate principal amount of 7.375% senior subordinated notes due 2013, or the 7.375% Notes. In June 2004, we issued an additional $100.0 million of 7.375% Notes; therefore, $200.0 million of the 7.375% Notes are currently outstanding. We pay interest on the 7.375% Notes semi-annually in January and July of each year. The 7.375% Notes mature in July 2013 and are guaranteed by certain of our subsidiaries. The 7.375% Notes were issued at a discount which will be amortized over the life of the 7.375% Notes into interest expense.

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 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. If we experience a change of control, there may be a requirement to repurchase all or a portion of the 7.375% Notes at 101% of the principal amount thereof plus accrued and unpaid interest, if any.

The 7.375% 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 Range and our subsidiary guarantors are permitted to incur under the bank credit facility and the indenture governing the 7.375% Notes.

6.375% Senior Subordinated Notes Due 2015

In March 2005, we issued $150.0 million of 6.375% senior subordinated notes due 2015, or the 6.375% Notes. We pay interest on the 6.375% Notes semi-annually in March and September of each year. The 6.375% Notes mature in March 2015 and are guaranteed by certain of our subsidiaries.

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 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. If we experience a change of control, there may be a requirement to repurchase all or a portion of the 6.375% Notes at 101% of the principal amount plus accrued and unpaid interest, if any.

The 6.375% 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 Range and our subsidiary guarantors are permitted to incur under the bank credit facility and the indenture governing the 6.375% 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 and the 6.375% Notes are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are either minor subsidiaries or indirect subsidiaries, or both.

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, 2005. 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 $365.8 million was available under the bank credit facility's restricted payment basket on December 31, 2005. The terms of both the 6.375% Notes and the 7.375% 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, 2005, approximately $432.9 million was available under the restricted payment baskets for both the 6.375% Notes and the 7.375% Notes.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2005 (in thousands):

Year Ended December 31:	
2006	$ -
2007	-
2008	-
2009	269,200
2010	-
2011	
Thereafter	350,000
	$ 619,200

(8) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Financial instruments include cash and equivalents, receivables, payables, debt and commodity and interest rate derivatives. The book value of cash and equivalents, receivables and payables is considered to be representative of fair value because of their short maturity. We mark to market all derivatives; therefore, the book value is assumed to be equal to fair value. The book value of bank borrowings is believed to approximate fair value because of their floating rate structure.

The following table sets forth the book and estimated fair values of financial instruments (in thousands):

	December 31, 2005		December 31, 2004	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Cash and equivalents	$ 4,750	$ 4,750	$ 18,382	$ 18,382
Accounts receivable	128,532	128,532	80,562	80,562
IPF receivable	-	-	4,508	4,508
Marketable securities (b)	21,769	21,769	9,866	9,866
Interest rate swaps	425	425	740	740
Total	155,476	155,476	114,058	114,058
Liabilities				
Accounts payable	(119,907)	(119,907)	(78,723)	(78,723)
Commodity swaps and collars	(231,049)	(231,049)	(71,931)	(71,931)
Long-term debt (a)	(616,148)	(619,523)	(620,556)	(633,556)
Total	(967,104)	(970,479)	(771,210)	(784,210)
	$ (811,628)	$ (815,003)	$ (657,152)	$ (670,152)

(a) Fair value based on quotes received from certain brokerage firms. Quotes for December 31, 2005 were 103% for the 7.375% Notes and 98% for the 6.375% Notes.
(b) Marketable securities held in the deferred compensation plans.

At December 31, 2005, we had open swap contracts covering 6.7 Bcf of gas at prices averaging $6.60 per mcf and 0.1 million barrels of oil at prices averaging $35.00 per barrel. We also had collars covering 82.8 Bcf of gas at weighted average floor and cap prices of $6.77 to $9.43 per mcf and 4.8 million barrels of oil at weighted average floor and cap prices of $45.21 to $56.58 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 loss of $231.0 million at December 31, 2005. 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 2005, 2004 and 2003, losses relating to our hedges of $171.1 million, $100.1 million and $60.4 million were realized, respectively. In addition, gains of $10.9 million were recognized in the fourth quarter of 2005 relating to positions which did not qualify for hedge accounting due to market volatility. Our hedging positions are recorded on our consolidated balance sheet at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX. Other revenues in the consolidated statement of operations were decreased for ineffective hedging losses on hedges that qualified for hedge accounting of $3.4 million and increased for ineffective gains of $712,000 in the twelve months ended December 31, 2005 and 2004 and decreased for ineffective hedging losses of $1.2 million in the year ended December 31, 2003.

The following table sets forth the hedging volumes by year as of December 31, 2005:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural gas			
2006	Swaps	10,788 Mmbtu/day	$ 6.43
2006	Collars	113,363 Mmbtu/day	$ 6.37 - $ 8.70
2007	Swaps	7,500 Mmbtu/day	$ 6.86
2007	Collars	83,500 Mmbtu/day	$ 6.93 - $9.63
2008	Collars	30,000 Mmbtu/day	$ 7.81 - $ 11.65
Crude Oil			
2006	Swaps	400 bbl/day	$ 35.00
2006	Collars	6,864 bbl/day	$ 39.83 - $ 49.05
2007	Collars	4,800 bbl/day	$ 51.42 - $ 61.87
2008	Collars	1,500 bbl/day	$ 50.00 - $ 74.12

We use 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. Under interest rate swap agreements, we agree to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. Our interest rate swaps are not designated as hedges and are marked to market each month as a component of interest expense. At December 31, 2005, we had interest rate swap agreements totaling $35.0 million. These swaps consist of two agreements at 1.8% which expire in June 2006. The fair value of the swaps at December 31, 2005, was an asset of $425,000 based on current quotes. On December 31, 2005, the 90-day LIBOR rate was 4.5%.

The combined fair value of net losses on oil and gas derivatives and net gains on interest rate swaps totaling $230.6 million appears as unrealized derivative gains and unrealized derivative losses on our consolidated balance sheet at December 31, 2005. 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.

(9) COMMITMENTS AND CONTINGENCIES

We are involved in various legal actions and claims arising in the ordinary course of business, the largest of which is *Jack Freeman, et al. v. Great Lakes Energy Partners L.L.C., et al.,* a class-action suit filed in 2000 which is currently pending against Great Lakes and Range in the state court of Chautauqua County, New York. The plaintiffs were seeking to recover actual damages and expenses plus punitive damages based on allegations that we sold gas to affiliates and gas marketers at low prices, that inappropriate post production expenses were used to reduce proceeds to the royalty owners and that improper accounting was used for the royalty owners' share of gas. A negotiated and pending settlement of this suit is pending the judge's review. An estimated settlement of $725,000 is reflected in general and administrative expense in the twelve months ended December 31, 2005. In management's opinion, we are not involved in any litigation, the outcome of which would have a material adverse effect on our financial position, results of operations or liquidity.

We lease certain office space and equipment under cancelable and non-cancelable leases, most of which expire within three years and may be renewed. Rent expense under such arrangements totaled $2.2 million, $1.7 million and $1.6 million in 2005, 2004 and 2003, respectively. We periodically enter into arrangements to purchase seismic data over several years. These commitments total $400,000 in both 2006 and 2007. Future minimum rental commitments under non-cancelable leases having remaining non-cancelable lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2006	$ 2,953
2007	2,018
2008	1,604
2009	1,297
2010 and thereafter	563
	$ 8,435

(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 effected 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 2004:

	Year Ended December 31,	
	2005	2004
Beginning balance	121,829,027	84,614,687
Issuances:		
Public offerings	6,900,000	26,910,000
In lieu of fees and bonuses	25,590	45,688
Stock options exercised	1,105,549	1,251,806
Restricted stock grants	-	121,350
Deferred compensation plan	20,885	5,506
Contributed to 401(k) Plan	33,018	56,460
Fractional shares	(1,023)	-
Exchanged for:		
5.9% Convertible Preferred	-	8,823,530
	8,084,019	37,214,340
Total	129,913,046	121,829,027
Treasury shares	(5,826)	-
Ending balance	129,907,220	121,829,027

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 the Permian basin properties. In December 2004, we completed a public offering of 8.6 million shares of common stock at $12.49 per share. Net proceeds from the offering of $103.2 million funded our acquisition of Pine Mountain. In June 2004, we completed a public offering of 18.3 million shares of common stock at $8.17 per share. Net proceeds from the offering and net proceeds from the concurrent sale of $100.0 million of our 7.375% Notes were used to fund our acquisition of Great Lakes (See also Note 4).

Treasury Stock

During 2005, we bought in open market purchases, 201,000 shares at an average price of $14.00. As of December 31, 2005, 195,000 of these shares had been used for equity compensation. The board of directors has approved of up to $5.0 million of additional repurchases of common stock based on market conditions and opportunities.

Shelf Registration Statement

In 2004, we filed a new universal shelf registration statement with the SEC registering $500.0 million aggregate amount of common stock, preferred stock and other equity and debt securities. In 2004, we issued 8.6 million shares of common stock under the shelf registration for an aggregate price of $107.8 million. In 2005, we issued 6.9 million shares of common stock under the shelf registration for an aggregate price of $113.9 million. As of December 31, 2005, we have $278.3 million of capacity remaining under the shelf.

(11) EMPLOYEE BENEFIT AND EQUITY PLANS

Stock and Option Plans

We have five equity 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. Information with respect to stock option and SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2002	4,923,216	$ 3.15
Granted	2,535,600	3.95
Exercised	(1,031,827)	2.37
Expired/canceled	(680,286)	3.64
Outstanding at December 31, 2003	5,746,703	3.58
Granted	2,514,750	7.74
Exercised	(1,252,905)	3.46
Expired/canceled	(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/canceled	(167,188)	9.08
Outstanding at December 31, 2005 [a]	8,742,305	$ 9.31

[a] Includes options outstanding under our inactive plans of 6,647,704 under the 1999 stock option plan, 324,000 under the outside director's stock option plan and 116,474 under the 1989 stock option plan. Outstanding at December 31, 2005 includes 1,570,125 of SARs.

The following table shows information with respect to outstanding stock options and SARs at December 31, 2005:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted Average Exercise Price
$ 1.29 - $4.99	3,547,096	3.57	$ 3.58	3,351,226	$ 3.55
5.00 – 9.99	1,720,108	3.17	7.02	970,361	7.02
10.00 – 14.99	458,863	3.95	11.46	155,518	12.78
15.00 – 19.99	2,904,488	4.32	16.73	871,329	16.73
20.00 – 24.99	30,000	4.76	22.79	-	-
25.00 – 29.99	81,750	4.87	25.80	-	-
Total	8,742,305	3.78	$ 9.31	5,348,434	$ 6.60

Restricted Stock Grants

In 2005, we issued 192,500 shares of restricted stock grants (from treasury stock) as compensation to directors, officers 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 officers and key 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, officers 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 officers and key employees with vesting over a three-year period. During 2003, we issued 351,000 restricted shares of common stock as compensation to directors, officers and key employees at an average price of $4.27. The restricted share awards included 204,000 that were granted to directors, which vested immediately, and 147,000 to officers and employees with vesting over a three-year period. We recorded compensation expense of $942,000, $567,000 and $191,000 in the twelve months ended December 31, 2005, 2004 and 2003, respectively, for restricted stock grants.

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 2005, 2004 and 2003, we contributed $1.5 million, $1.2 million and $912,000, respectively, to the 401(k) Plan. 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, 2005, there were no rights outstanding to purchase shares and there were 373,000 remaining shares authorized to be granted.

Deferred Compensation Plan

In 1996, the Board of Directors adopted a deferred compensation plan or 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, or the 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 non-cash stock compensation 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 stockholder's equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the market value of our common stock held in the Rabbi Trust is charged or credited to non-cash stock compensation expense each quarter. We recorded mark-to-market expenses related to deferred compensation of $29.5 million in 2005, $19.2 million in 2004 and $6.6 million in 2003. 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.

(12) INCOME TAXES

Our income tax expense for the years ended December 31, 2005, 2004 and 2003, was $66.4 million, $24.5 million and $18.5 million, respectively. In addition, $2.4 million of tax expense was recognized as part of the cumulative effect of changes in accounting principles at December 31, 2003. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Federal statutory tax rate	35%	35%	35%
State	2	2	2
Consolidated effective tax rate	37%	37%	37%
Income taxes paid	$ 615	$ 150	$ 110

Income tax provision (benefit) attributable to income before cumulative effect of change in accounting principle consists of the following:

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Current:			
U.S. federal	$ -	$ (192)	$ 191
U.S. state and local	1,071	(53)	(21)
	$ 1,071	$ (245)	$ 170
Deferred:			
U.S. federal	$ 61,767	$ 23,450	$ 17,329
U.S. state and local	3,530	1,340	990
	$ 65,297	$ 24,790	$ 18,319

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

	December 31,	
	2005	2004
	(in thousands)	
Deferred tax assets		
Net operating loss carryover	$ 76,944	$ 82,206
Allowance for doubtful accounts	1,166	1,303
Net unrealized loss in OCI	85,462	25,930
Deferred compensation	27,721	13,329
AMT credits and other	44,738	14,414
Total deferred tax assets	236,031	137,182
Deferred tax liabilities		
Depreciation and depletion	(346,070)	(225,142)
Valuation allowance	(3,101)	(3,443)
Total deferred tax liabilities	(349,171)	(228,585)
Net deferred tax liability	$ (113,140)	$ (91,403)

At December 31, 2005, deferred tax liabilities exceeded deferred tax assets by $113.1 million, with $85.5 million of deferred tax assets related to net deferred hedging losses 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, 2005, we had regular net operating loss ("NOL") carryovers of $207.2 million and alternative minimum tax ("AMT") NOL carryovers of $179.2 million that expire between 2012 and 2025. 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, 2005, we have AMT credit carryovers of $0.7 million that are not subject to limitation or expiration.

(13) 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,		
	2005	2004	2003
Numerator:			
Income before cumulative effect of changes in accounting principles	$ 111,011	$ 42,231	$ 30,924
Preferred stock dividends	-	(5,163)	(803)
Numerator for basic earnings per share before cumulative effect of changes in accounting principles	111,011	37,068	30,121
Cumulative effect of accounting change	-	-	4,491
Numerator for basic earnings per share	$ 111,011	$ 37,068	$ 34,612
Numerator for diluted earnings per share before cumulative effect of changes in accounting principles	$ 111,011	$ 37,068	$ 30,924
Cumulative effect of accounting change	-	-	4,491
Numerator for diluted earnings per share after assumed conversions and cumulative effect of changes in accounting principles	$ 111,011	$ 37,068	$ 35,415
Denominator:			
Weighted average shares outstanding	126,339	96,050	83,694
Stock held in deferred compensation plan and treasury shares	(2,209)	(2,506)	(2,286)
Weighted average shares, basic	124,130	93,544	81,408
Effect of dilutive securities:			
Weighted average shares outstanding	126,339	96,050	83,694
Employee stock options and other	2,863	1,948	663
Treasury shares	(76)	-	-
Common shares assumed for 5.9% convertible preferred stock	-	-	2,418
Dilutive potential common shares for diluted earnings per share	129,126	97,998	86,775
Earnings per share basic and diluted:			
Before cumulative effect of accounting change			
Basic	$ 0.89	$ 0.40	$ 0.37
Diluted	$ 0.86	$ 0.38	$ 0.36
After cumulative effect of accounting change			
Basic	$ 0.89	$ 0.40	$ 0.42
Diluted	$ 0.86	$ 0.38	$ 0.41

Options to purchase 318,200 and 193,350 shares of common stock were outstanding but not included in the computation of diluted net income per shares for the twelve months ended December 31, 2004 and 2003, respectively, 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. Our 5.9% convertible preferred stock was antidilutive in the third quarter and the nine months ended September 30, 2004.

(14) 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 twelve months ended December 31, 2005, four customers 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 twelve months ended December 31, 2004, two customers accounted for 10% or more of total oil and gas revenues and the combined sales to those two customers accounted for 25% of total oil and gas revenues. For the year ended December 31, 2003, three customers accounted for 10% or more of total oil and gas revenue and combined sales to those three customers accounted for 49% 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.

(15) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years. Significant producing property acquisitions in 2004 affect the comparability of the financial data (in thousands, except per share data):

	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	758	661	2,578
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	141,845	166,468	535,957
Costs and expenses					
Direct operating	14,808	17,419	16,676	17,729	66,632
Production and ad valorem taxes	5,755	7,034	8,457	10,270	31,516
Exploration	3,271	9,124	7,174	9,868	29,437
General and administrative	6,603	6,241	7,183	9,405	29,432
Non-cash stock compensation	4,067	5,276	20,118	5,789	35,250
Interest expense and dividends on trust preferred	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	102,418	98,233	358,578
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

	2004				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 65,368	$ 67,553	$ 85,574	$ 97,208	$ 315,703
Transportation and gathering	467	344	296	1,095	2,202
Gain on retirement of securities	-	(34)	(5)	-	(39)
Other	(2,302)	833	349	3,961	2,841
Total revenue	63,533	68,696	86,214	102,264	320,707
Costs and expenses					
Direct operating	9,995	10,406	12,718	13,189	46,308
Production and ad valorem taxes	4,250	4,801	5,331	6,122	20,504
Exploration	3,567	4,200	4,615	8,837	21,219
General and administrative	4,436	5,052	5,301	5,845	20,634
Non-cash stock compensation	4,385	4,303	4,829	5,659	19,176
Interest expense and dividends on trust preferred	4,145	4,422	6,913	7,639	23,119
Depletion, depreciation and amortization	22,248	22,444	26,306	31,973	102,971
Total costs and expenses	53,026	55,628	66,013	79,264	253,931
Income before income taxes	10,507	13,068	20,201	23,000	66,776
Income tax (benefit)					
Current	-	44	(132)	(157)	(245)
Deferred	3,887	4,835	7,454	8,614	24,790
	3,887	4,879	7,322	8,457	24,545
Net income	6,620	8,189	12,879	14,543	42,231
Preferred dividends	(738)	(737)	(737)	(2,951)	(5,163)
Net income available to common stockholders	$ 5,882	$ 7,452	$ 12,142	$ 11,592	$ 37,068
Earnings per common share					
Basic	$ 0.07	$ 0.09	$ 0.12	$ 0.11	$ 0.40
Diluted	$ 0.07	$ 0.08	$ 0.11	$ 0.11	$ 0.38

(16) 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", or SFAS 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,		
	2005	2004	2003
		(in thousands)	
Oil and gas properties:			
Properties subject to depletion	$ 2,519,454	$ 2,082,236	$ 1,350,616
Unproved properties	28,636	14,790	12,195
Total	2,548,090	2,097,026	1,362,811
Accumulated depreciation, depletion and amortization	(806,908)	(694,667)	(639,429)
Net capitalized costs	$ 1,741,182	$ 1,402,359	$ 723,382

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

Costs Incurred for Property Acquisition, Exploration and Development [a]

	Year Ended December 31,		
	2005	2004	2003
		(in thousands)	
Acquisitions:			
Acreage purchases	$ 20,674	$ 9,690	$ 5,580
Unproved leasehold	-	4,043	-
Proved oil and gas properties	131,748	522,126	88,588
Purchase price adjustment [b]	20,966	79,352	-
Asset retirement obligations	119	17,524	2,135
Development	252,574	144,007	80,482
Exploration [c]	59,539	31,830	22,564
Gas gathering facilities:			
Acquisitions	8	15,539	4,622
Development	11,415	4,778	2,951
Subtotal	497,043	828,889	206,922
Asset retirement obligations	(1,730)	3,994	4,597
Total costs incurred	$ 495,313	$ 832,883	$ 211,519

(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 $29,437, $21,219 and $13,946 of exploration costs expensed in 2005, 2004 and 2003, respectively.

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, 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. The average prices used at December 31, 2003 to estimate reserve information were $29.48 per barrel for oil, $19.93 per barrel for natural gas liquids and $6.03 per mcf for gas, using benchmark prices of $32.52 per barrel and $6.19 per Mmbtu.

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents (Mmcfe)
Proved developed and undeveloped reserves:			
Balance, December 31, 2002	22,952	440,267	577,977
Revisions	445	4,625	7,294
Extensions, discoveries and additions	3,331	48,364	68,351
Purchases	8,758	37,734	90,284
Sales	(39)	(1,076)	(1,312)
Production	(2,424)	(43,510)	(58,053)
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
Proved developed reserves:			
December 31, 2003	24,912	344,187	493,659
December 31, 2004	27,715	580,006	746,299
December 31, 2005	33,029	724,876	923,050

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 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.

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.

4. 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.
5. 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,		
	2005	2004	2003
		(in thousands)	
Future cash inflows	$ 13,520,985	$ 7,109,349	$ 3,803,479
Future costs:			
Production	(2,266,828)	(1,472,484)	(842,052)
Development	(825,261)	(601,447)	(274,029)
Future net cash flows before income taxes	10,428,896	5,035,418	2,687,398
Future income tax expense	(3,496,799)	(1,523,915)	(740,965)
Total future net cash flows before 10% discount	6,932,097	3,511,503	1,946,433
10% annual discount	(3,547,787)	(1,762,092)	(943,452)
Standardized measure of discounted future net cash flows	$ 3,384,310	$ 1,749,411	$ 1,002,981

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

	As of December 31,		
	2005	2004	2003
		(in thousands)	
Beginning of period	$ 1,749,411	$ 1,002,981	$ 499,633
Revisions to previous estimates:			
Changes in prices	1,633,812	129,916	160,932
Revisions in quantities	59,244	(59,591)	267,906
Changes in future development costs	(367,732)	(399,562)	(100,656)
Accretion of discount	239,636	139,582	96,361
Net change in income taxes	(856,115)	(254,114)	(103,375)
Purchases of reserves in place	321,022	1,059,294	145,772
Additions to proved reserves from extensions, discoveries and improved recovery	814,973	355,742	110,358
Production	(425,902)	(248,891)	(177,085)
Development costs incurred during the period	143,918	72,144	51,005
Sales of natural gas and oil	(769)	(71,441)	(2,117)
Timing and other	72,812	23,351	54,247
End of period	$ 3,384,310	$ 1,749,411	$ 1,002,981

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

Exhibit No.	Description
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 10K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7.375% Senior Subordinated Notes due 2013 (contained as an 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 (contained as 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)
10.1	Consulting Agreement dated May 21, 2003 by and between Range and Thomas J. Edelman (incorporated by reference to Exhibit 10.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
10.2	Second Amended and Restated Credit Agreement as of June 23, 2004 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and Bank One NA, and the institutions named (therein) as lenders, Bank One NA as Administrative Agent and Banc One Capital Market, Inc. as Sale Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 29, 2004)
10.3	First Amendment to the Second Amended and Restated Credit Agreement dated December 6, 2004 among Range and Great Lakes Energy Partners L.L.C.(as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with SEC on December 10, 2004)
10.4	Second Amendment to the Second Amended and Restated Credit Agreement dated March 2, 2005 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on March 8, 2005)
10.5*	Third Amendment to the Second Amended and Restated Credit Agreement dated March 2, 2005 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.6*	Fourth Amendment to the Second Amended and Restated Credit Agreement dated March 2, 2005 among Range and Great Lakes Energy Partners L.L.C. (as borrowers) and J.P.Morgan Chase Bank, N.A. (successor to merger to Bank One, N.A.), a national banking association (J.P.Morgan Chase) and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.7	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)
10.8	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)
10.9	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)
10.10	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)
10.11	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)

10.12	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)
10.13	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)
10.14	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)
10.15	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)
10.16	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)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	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)
10.22	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)
10.23	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)
10.24	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)
10.25	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)
10.26	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)
10.27	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)
10.28	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.

EXHIBIT 21

RANGE RESOURCES CORPORATION

Subsidiaries of Registrant

Name	Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Range Production Company	Delaware	100%
Range Energy Services Company	Delaware	100%
Range Holdco, Inc.	Delaware	100%
Range Energy I, Inc.	Delaware	100%
Range Gathering & Processing Company	Delaware	100%
Range Gas Company	Delaware	100%
RRC Operating Company	Ohio	100%
Range Energy Finance Corporation	Delaware	100%
Range Energy Ventures Corporation	Delaware	100%
Gulfstar Energy, Inc.	Delaware	100%
Gulfstar Seismic, Inc.	Delaware	100%
Domain Energy International Corporation [a]	British Virgin Islands	100%
Energy Assets Operating Company	Delaware	100%
Range Operating New Mexico, Inc.	Delaware	100%
PMOG Holdings, Inc.	Delaware	100%
Pine Mountain Acquisition, Inc.	Delaware	100%
Pine Mountain Oil & Gas, Inc.	Virginia	100%
Great Lakes Energy Partners, L.L.C.	Delaware	100%
Ohio Interstate Gas Transmission Company	Ohio	100%
Victory Energy Partners, L.L.C.	Texas	100%

[a] Dormant subsidiary with no assets.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FRIM

We consent to the incorporation by reference in the Registration Statements on Form S-3/A (Nos. 333-76837 and 333-118417) on Form S-4 (Nos. 333-78231, 333-108516, 333-117834 and 333-123534) and on Form S-8 (Nos. 333-125665, 333-90760, 333-63764, 333-40380, 333-30534, 333-88657, 333-69905, 333-62439, 333-44821, 333-10719, 333-105895 and 333-116320) of Range Resources Corporation and in the related Prospectuses of our reports dated February 21, 2006 with respect to the consolidated financial statements of Range Resources Corporation and subsidiaries, Range Resources Corporation management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Range Resources Corporation and subsidiaries, included in this Annual Report (Form 10-K) for the year ended December 31, 2005.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 21, 2006

EXHIBIT 23.2

CONSENT OF H.J. GRUY AND ASSOCIATES, INC.

We hereby consent to the use of the name H.J. Gruy and Associates, Inc., and of references to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report, or information contained therein, dated February 13, 2006, prepared for Range Resources Corporation in the Range Resources Corporation Annual Report on Form 10-K for the year ended December 31, 2005. We are unable to verify the accuracy of the reserves and discounted present worth values contained therein because our estimates of reserves and discounted present worth have been combined with estimates of reserves and present worth prepared by other petroleum consultants.

H.J. GRUY AND ASSOCIATES, INC.

February 20, 2006
Houston, Texas

EXHIBIT 23.3

CONSENT OF DEGOLYER AND MACNAUGHTON

We hereby consent to the reference to DeGolyer and MacNaughton under the heading "Item 2. Properties – Proved Reserves" in the Annual Report on Form 10-K of Range Resources Corporation for the year ended December 31, 2005, to which this consent is an exhibit. We also consent to the incorporation of information contained in our "Appraisal Report as of December 31, 2005, of Certain Interests owned by Range Resources Corporation," provided, however, that we are necessarily unable to verify the accuracy of the reserves and discounted present worth values contained therein because our estimates of reserves and discounted present worth have been combined with estimates of reserves and present worth prepared by other petroleum consultants.

DEGOLYER AND MACNAUGHTON

Dallas, Texas
February22, 2006

EXHIBIT 23.4

CONSENT OF WRIGHT & COMPANY, INC.

We hereby consent to the incorporation by reference of our name in the Annual Report on Form 10-K of Range Resources Corporation (the "Company") for the fiscal year ended December 31, 2005, to which this consent is an exhibit.

WRIGHT & COMPANY, INC.

Brentwood, Tennessee
February 20, 2006

EXHIBIT 31.1

CERTIFICATION

I, John H. Pinkerton, certify that:

1. I have reviewed this report on Form 10-K of Range Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2006

/s/ JOHN H. PINKERTON
John H. Pinkerton
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Roger S. Manny, certify that:

1. I have reviewed this report on Form 10-K of Range Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2006

/s/ ROGER S. MANNY

Roger S. Manny
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
PRESIDENT AND CHIEF EXECUTIVE OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying report on Form 10-K for the period ending December 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, John H. Pinkerton, President and Chief Executive Officer of Range Resources Corporation (the “Company”), hereby certify that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ JOHN H. PINKERTON
John H. Pinkerton
February 22, 2006

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying report on Form 10-K for the period ending December 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Roger S. Manny, Chief Financial Officer of Range Resources Corporation (the "Company"), hereby certify that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ ROGER S. MANNY
Roger S. Manny
February 22, 2006