GOODRICH PETROLEUM CORP
Form 10-K
March 14, 2007
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

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

For the fiscal year ended December 31, 2006

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

Commission file number: 001-7940

# GOODRICH PETROLEUM CORPORATION

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **76-0466193** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |
| **808 Travis, Suite 1320 Houston, Texas** | **77002** |
| **(Address of principal executive offices)** | **(Zip Code)** |

**(713) 780-9494 (Registrant s telephone number)**

| Title of each class | Name of exchange on which registered |
|---|---|

Securities Registered Pursuant to Section 12 (b) of the Act:

| | |
|---|---|
| Common Stock, par value $0.20 per share | New York Stock Exchange |

Securities Registered Pursuant to Section 12 (g) of the Act:

| | |
|---|---|
| Series A and B Preferred Stock, $1.00 par value | NASDAQ Capital Market |

**None**

Indicate by check mark if the Registrant is a well-known seasoned issuer (as defined in Rule 405 of the Securities Act). Yes ¨ No x

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 *x*

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 *x* 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-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer *x* Non-accelerated filer ¨

Indicate by check mark whether the Registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ¨ No x

The aggregate market value of Common Stock, par value $0.20 per share (Common Stock), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange National Market on June 30, 2006) the last business day of the registrant s most recently completed second fiscal quarter was approximately $348 million. The number of shares of the registrant s common stock outstanding as of March 9, 2007 was 28,288,838.

**Documents Incorporated By Reference:**

Portions of Goodrich Petroleum Corporation s definitive Proxy Statement are incorporated by reference in Part III of this Form 10-K.

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**GOODRICH PETROLEUM CORPORATION**

**ANNUAL REPORT ON FORM 10-K**

**FOR THE FISCAL YEAR ENDED**

**December 31, 2006**

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## PART I

**Items 1 and 2.** ***Business and Properties*****.**

### General

Goodrich Petroleum Corporation and subsidiaries ( we or the Company ) is an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the Cotton Valley Trend of East Texas and Northwest Louisiana and in the transition zone of South Louisiana. We own working interests in 233 active oil and gas wells located in 25 fields in three states. At December 31, 2006, Goodrich had estimated proved reserves of approximately 187.0 Bcf of natural gas and 3.2 MMBbls of oil and condensate, or an aggregate of 206.2 Bcfe with a pre-tax present value of future net cash flows, discounted at 10% of $214.2 million and an after-tax present value of discounted future net cash flows of $200.3 million, which is also referred to as the standardized measure of discounted future net cash flows. See Note 13 Oil and Gas Producing Activities (Unaudited) Oil and Natural Gas Reserves to our consolidated financial statements for a reconciliation to the standardized measure of discounted future net cash flows.

Our principal executive offices are located at 808 Travis Street, Suite 1320, Houston, Texas 77002.

### Business Strategy

Our business strategy is to provide long term growth in net asset value per share, through the growth and expansion of our oil and gas reserves and production. We focus on adding reserve value through the development of our relatively low risk development drilling program in the Cotton Valley Trend. We continue to aggressively pursue the acquisition and evaluation of prospective acreage, oil and gas drilling opportunities and potential property acquisitions.

Several of the key elements of our business strategy are the following:

*Exploit and Develop Existing Property Base*. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest production and reserve growth potential. We intend to concentrate on developing our multi-year inventory of drilling locations in the Cotton Valley Trend. Our Cotton Valley Trend inventory is currently estimated to include over 1,900 possible future drilling locations, based generally on 40 acre spacing. We are continually performing field studies of our existing properties and reevaluating the possibility of additional exploration and development opportunities on these properties utilizing advanced technologies available at present.

*Expand Acreage Position in the Cotton Valley Trend*. We have increased our acreage position from approximately 129,000 gross acres at December 31, 2005, to 163,200 gross acres as of December 31, 2006. We concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in the Cotton Valley Trend and other areas, which exhibit similar characteristics to our existing properties.

*Focus on Low Operating Costs.* We continually seek ways to minimize lease operating expenses. We will continue to seek to control costs to the greatest extent possible by controlling our operations. We announced in January 2007, that we had entered into an agreement to sell substantially all of our properties in South Louisiana. See Note 12 Acquisitions and Divestitures to our consolidated financial statements. These properties have higher operating costs per Mcfe than our other properties. Upon closing of the sale, we expect our ongoing operating costs per Mcfe to decrease due to the lower cost nature of our Cotton Valley Trend operations.

*Maintain an Active Hedging Program.* We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically fixed price swaps and costless collars. The level of our hedging activity and the duration of the

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instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. For the first quarter of 2007, we currently have an average of 10,000 MMbtu per day of gas hedged at an average price of $7.77 per MMbtu and 400 Bbls per day of oil hedged at an average price of $53.35 per Bbl. Additionally, we have 25,000 MMbtu per day collared in the first quarter of 2007, and 30,000 MMbtu per day collared in the second, third and fourth quarters of 2007, at average floor and ceiling prices respectively, of $7.80-$12.42 and $7.67-$12.67. Subsequent to year end, we have entered into a series of physical sales contracts which will result in us selling approximately 18,500 MMbtu of gas per day in calendar year 2008 for an average price of $7.95 per MMbtu before transportation charges.

## Oil and Gas Operations and Properties

### Cotton Valley Trend

*Overview.* As of December 31, 2006, approximately 84% of our proved oil and gas reserves were in the Cotton Valley Trend of East Texas and Northwest Louisiana. We spent approximately 78% of our 2006 capital expenditures of $269.4 million in the Cotton Valley Trend. As of year-end, we have acquired or farmed in leases totaling approximately 163,200 gross (102,000 net) acres and are continually attempting to acquire additional acreage in the area. As of February 15, 2007, we have acquired an additional 16,800 gross (8,000 net) acres, bringing the total currently to 180,000 gross (110,000 net) acres. Company operated acreage comprised 117,000 acres (with an average working interest of approximately 81%) and non-operated acreage comprised 46,000 gross acres (with an average working interest of approximately 40%). As of the year end, we have drilled and/or completed 156 Cotton Valley Trend wells with a success rate in excess of 99%. Our current Cotton Valley Trend drilling activities are located in six primary leasehold areas in East Texas and Northwest Louisiana as further described below:

*Dirgin-Beckville.* The Dirgin-Beckville area is located in Rusk and Panola Counties in Texas. As of year end, we had acquired leases totaling approximately 12,600 gross (11,400 net) acres with an average working interest of approximately 99%. As of December 31, 2006, we had successfully completed 52 Cotton Valley Trend wells in the Dirgin-Beckville area.

*North Minden.* The North Minden area is located in Rusk County, Texas. As of year end, we had acquired leases totaling approximately 32,800 gross (27,400 net) acres with a working interest of approximately 93%. As of December 31, 2006, we had successfully drilled 60 Cotton Valley Trend wells in the North Minden area.

*South Henderson.* The South Henderson area is located in Rusk County, Texas. As of year end, we had acquired leases totaling approximately 13,800 gross (11,100 net) acres with an average working interest of approximately 80%. As of December 31, 2006, we had successfully completed 7 Cotton Valley Trend wells in the South Henderson area.

*Bethany-Longstreet.* The Bethany-Longstreet field is located in Caddo and DeSoto Parishes in Northwest Louisiana. As of December 31, 2006, we had successfully drilled 14 Cotton Valley Trend wells in the field. Our initiative in this area began in the third quarter of 2003, when we obtained, via farmout, exploration rights to approximately 21,300 gross (14,900 net) acres in the field. We have an average 70% working interest in the Bethany-Longstreet field.

*Angelina River.* The Angelina River area is located in Angelina, Nacogdoches, and Cherokee Counties, Texas. We had acquired approximately 51,800 gross (22,800 net) acres in the area as of December 31, 2006. As of February 15, 2007, we had acquired an additional 16,800 gross (8,400 net) acres, bringing the total to 68,600 gross (31,200 net) acres. We own an average 50% working interest in the acreage. We currently are the operator of 22,600 gross acres, while owning a 40% non-operated interest in 44,200 gross acres. At year end, we had successfully drilled and logged 6 wells and recompleted three additional wells in the field.

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*Other Cotton Valley Trend.* We also own 30,900 gross (14,400 net) acres in four separate areas of the Cotton Valley Trend in Harrison, Smith and Upshur Counties, Texas, and Bienville Parish, Louisiana, with an average working interest of approximately 65%. We have successfully drilled and logged 13 wells, with one well in Harrison County, Texas unsuccessful.

*Production and Reserves*. For the wells completed to date in the Cotton Valley Trend, the average initial gross production rate per well was approximately 1,700 Mcfe per day. This average initial gross production rate is approximately 200 Mcfe per day higher than that calculated on a similar basis at the end of 2005. Initial production from the Cotton Valley Trend wells commenced in June 2004 and for the quarter ended December 31, 2006, gross production from the initial and subsequently drilled wells averaged approximately 54,500 Mcfe per day. Net production averaged 33,100 Mcfe per day for the fourth quarter of 2006.

**South Louisiana**

In January 2007, we entered into an agreement to sell substantially all of our South Louisiana properties to a private company with an anticipated closing date of late March, 2007. The St. Gabriel, Bayou Bouillon, and Plumb Bob fields will not be included in the sale and we continue to own and operate our interests in these fields. See Note 12 Acquisitions and Divestitures to our consolidated financial statements.

*Overview.* As of December 31, 2006, approximately 15% of our proved oil and natural gas reserves were in the transition zone of South Louisiana. This region refers to the geographic area that covers the onshore and in-land waters of South Louisiana lying in the southern half of Louisiana, which is one of the most prolific oil and natural gas producing sedimentary basins. Our production in this region during 2006, came predominately from the following areas:

*Burrwood and West Delta 83 Fields*. The Burrwood/West Delta 83 fields, located in Plaquemines Parish, Louisiana, were discovered in 1955 by Chevron. At December 31, 2006, we had an interest in 77 active wells in the fields, with 21 producing at that time. By July, 2006, we had restored all of our production from the fields to pre-hurricane Katrina levels. We had an average 55% working interest in the production and a 65% working interest in the leasehold in the fields.

*Lafitte Field.* The Lafitte field is located in Jefferson Parish, Louisiana and was discovered in 1935 by Texaco. At December 31, 2006, we owned a non-operated, 49% working interest and had interests in 30 active producing wells in the Lafitte field.

*Second Bayou Field.* The Second Bayou field is located in Cameron Parish, Louisiana and was discovered in 1955 by the Sun Texas Company. As of December 31, 2006, we served as the operator of eight active wells, all of which had been restored to production levels experienced prior to Hurricane Rita. At December 31, 2006, we had an average working interest of approximately 31% in 411 gross acres.

*St.Gabriel Field.* This field was not part of the sale of properties. The St. Gabriel field is located in Ascension and Iberville Parishes in southern Louisiana and was originally discovered by Shell Oil Company in 1939. In July 2004, we announced that we had acquired a 70% working interest in 3-D seismic permits and oil and gas lease options enabling us to acquire an approximate 30 square mile 3-D seismic survey over the field. We commenced shooting the 3-D seismic survey in July 2004 and data acquisition was completed in September 2004. As of December 31, 2006, we had successfully drilled one well in the field.

*Other Fields*. As of December 31, 2006, we maintained ownership interests in acreage and/or wells in several additional fields in Louisiana, including the (i) Lake Raccourci field, located in Terrebonne Parish, (ii) Pecan Lake field, located in Cameron Parish, (iii) Plumb Bob field, located in St. Martin Parish, and (iv) Bayou Bouillon field in St. Martin Parish, the first two of which are part of the sale properties.

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**Other Properties**

As of December 31, 2006, we maintain ownership interests in acreage and/or wells in several additional fields including the (i) Mary Blevins field, located in Smith County, Texas, (ii) Midway field, located in San Patricio County, Texas, (iii) Mott Slough field, located in Wharton County, Texas and (iv) the Garfield Unit, located in Kalkaska County, Michigan.

**Oil and Natural Gas Reserves**

The following tables set forth summary information with respect to our proved reserves as of December 31, 2006 and 2005, as estimated by us by compiling reserve information derived from the evaluations performed by Netherland, Sewell & Associates, Inc. ( NSA ), our independent reserve engineers. See Note 13 Oil and Gas Producing Activities (unaudited) to our consolidated financial statements for additional information.

| | Oil | Gas | Total | PV10 Value (1) |
|---|---|---|---|---|
| | (MBbls) | (MMcf) | (MMcfe) | (000s) |
| December 31, 2006 | | | | |
| Proved Developed | 1,862 | 76,679 | 87,852 | $ 208,490 |
| Proved Undeveloped | 1,339 | 110,333 | 118,365 | 5,697 |
| Total Proved | 3,201 | 187,012 | 206,217 | 214,187 |
| Discounted Future Income Taxes | | | | (13,906) |
| Standardized Measure of Discounted Future Net Cash Flows (1) | | | | $ 200,281 |
| December 31, 2005 | | | | |
| Proved Developed | 1,796 | 56,700 | 67,474 | $ 328,058 |
| Proved Undeveloped | 3,177 | 86,263 | 105,325 | 259,618 |
| Total Proved | 4,973 | 142,963 | 172,799 | 587,676 |
| Discounted Future Income Taxes | | | | (177,056) |
| Standardized Measure of Discounted Future Net Cash Flows (1) | | | | $ 410,620 |

(1) The PV10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. PV10 may be considered a non-GAAP measure as defined by the SEC. We believe that the presentation of the PV10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors utilize our PV10 as a basis for comparison of the relative size and value of our reserves to other companies. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves

after estimated future income tax, discounted at 10%. Neither PV10 Value nor standardized measure of discounted future net cash flows reflects the impact of hedging transactions.

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the pre-tax PV10 Value amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to our properties.

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In accordance with the guidelines of the SEC, the engineers estimates of future net revenues from our properties and the pre-tax PV10 Value thereof are made using oil and natural gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The prices as of December 31, 2006 and 2005, used in such estimates averaged $5.64 and $10.54 per Mcf, respectively, of natural gas and $57.75 and $58.80 per Bbl, respectively, of crude oil/condensate. These prices do not include the impact of hedging transactions.

**Productive Wells**

The following table sets forth the number of active well bores in which we maintain ownership interests as of December 31, 2006:

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| | **Gross (2)** | **Net (3)** | **Gross (2)** | **Net (3)** | **Gross (2)** | **Net (3)** |
| Louisiana (1) | 59.00 | 28.60 | 26.00 | 14.52 | 85.00 | 43.12 |
| Michigan | | | 1.00 | 0.01 | 1.00 | 0.01 |
| Texas | 4.00 | 2.59 | 143.00 | 125.05 | 147.00 | 127.64 |
| Total Productive Wells | 63.00 | 31.19 | 170.00 | 139.58 | 233.00 | 170.77 |

(1) In late March 2007, we expect to close the sale of substantially all of our South Louisiana properties to a private company. After adjusting for the sale in late March 2007, we will maintain ownership interests in a total of 20.00 gross (13.23 net) wells, of which 1.00 gross (0.70 net) wells produced oil and 19.00 gross (12.53 net) wells produced natural gas, in Louisiana.

(2) Does not include royalty or overriding royalty interests.

(3) Net working interest.

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, 33 wells had multiple completions.

**Acreage**

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2006. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |

| | | | | | | |
|---|---|---|---|---|---|---|
| Louisiana (1) | 31,974 | 17,252 | 40,008 | 20,104 | 71,982 | 37,356 |
| Michigan | 1,920 | 19 | | | 1,920 | 19 |
| Texas | 43,037 | 38,933 | 76,760 | 39,418 | 119,797 | 78,351 |
| Total | 76,931 | 56,204 | 116,768 | 59,522 | 193,699 | 115,726 |

(1) In late March, 2007, we expect to close the sale of substantially all of our South Louisiana properties to a private company. After adjusting for the sale as of late March, 2007, we will have under lease in Louisiana a total of 44,300 gross (24,000 net) acres, of which 7,800 gross (5,200 net) acres are classified as developed and 36,500 gross (18,800 net) acres are classified as undeveloped.

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Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and gas industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The natural gas and oil leases in which we have an interest are for varying primary terms; however, most of our developed lease acreage is beyond the primary term and is held so long as natural gas or oil is produced.

**Operator Activities**

We operate a majority in value of our producing properties, and will generally seek to become the operator of record on properties we drill or acquire in the future.

**Drilling Activities**

The following table sets forth our drilling activities for the last three years. As denoted in the following table, Gross wells refer to wells in which a working interest is owned, while a Net well is deemed to exist when the sum of the fractional working interests we own in gross wells equals one.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development Wells: | | | | | | |
| Productive | 99.00 | 75.89 | 57.00 | 51.72 | 15.00 | 12.44 |
| Non-Productive | 1.00 | 1.00 | 1.00 | 0.42 | 2.00 | 0.89 |
| Total | 100.00 | 76.89 | 58.00 | 52.14 | 17.00 | 13.33 |
| Exploratory Wells: | | | | | | |
| Productive | 4.00 | 1.60 | 5.00 | 3.00 | 3.00 | 2.55 |
| Non-Productive | 1.00 | 0.56 | 1.00 | 0.49 | | |
| Total | 5.00 | 2.16 | 6.00 | 3.49 | 3.00 | 2.55 |
| Total Wells: | | | | | | |
| Productive | 103.00 | 77.49 | 62.00 | 54.72 | 18.00 | 14.99 |
| Non-Productive | 2.00 | 1.56 | 2.00 | 0.91 | 2.00 | 0.89 |
| Total | 105.00 | 79.05 | 64.00 | 55.63 | 20.00 | 15.88 |

At December 31, 2006, we had 16 development wells (12.4 net) and one exploratory well that were in the process of being drilled and/or completed.

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**Net Production, Unit Prices and Costs**

The following table presents certain information with respect to natural gas and oil production attributable to our interests in all of our fields, the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2006.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Net Production: | | | |
| Natural gas (MMcf) | 13,001 | 6,237 | 4,818 |
| Oil and Condensate (MBbls) | 474 | 408 | 475 |
| Total (MMcfe) | 15,843 | 8,686 | 7,669 |
| Average Net Daily Production: | | | |
| Natural gas (Mcf) | 35,620 | 17,087 | 13,163 |
| Oil and Condensate (Bbls) | 1,298 | 1,118 | 1,299 |
| Natural gas equivalents (Mcfe) | 43,406 | 23,797 | 20,957 |
| Revenues (in thousands) (1): | | | |
| Natural gas | $ 86,621 | $ 53,746 | $ 29,485 |
| Oil and condensate (Bbl) | $ 27,075 | $ 14,641 | $ 15,376 |
| Total | $ 113,696 | $ 68,387 | $ 44,861 |
| Average Realized Sales Price Per Unit (1): | | | |
| Natural gas (Mcf) | $ 6.66 | 8.62 | 6.12 |
| Oil and condensate (Bbl) | $ 57.12 | 29.91 | 32.35 |
| Average realized price (Mcfe) | $ 7.18 | 7.88 | 5.85 |
| Other Data: | | | |
| Lease operating expense (per Mcfe) | $ 1.38 | $ 1.14 | $ 0.97 |
| Production taxes (per Mcfe) | $ 0.38 | $ 0.47 | $ 0.40 |
| DD&A (per Mcfe) | $ 3.32 | $ 2.94 | $ 1.51 |
| Exploration (per Mcfe) | $ 0.95 | $ 0.79 | $ 0.58 |

(1) Revenues and Average Realized Sales Price Per Unit amounts shown are net of the effect of settled derivatives for oil and condensate in 2006, 2005 and 2004, and for natural gas in 2004 only.

For a discussion of comparative changes in our production volumes, revenues and operating expenses for the three years ended December 31, 2006, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operations .

**Oil and Gas Marketing and Major Customers**

*Marketing*. Essentially all of our natural gas production is sold under spot or market-sensitive contracts to various gas purchasers on short-term contracts. Our condensate and crude oil production is sold to various purchasers under short-term rollover agreements based on current market prices.

*Customers*. Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from these sources as a percent of oil and gas revenues for the periods presented were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Louis Dreyfus Corporation | 35% | 34% | 45% |
| Shell Trading | 15% | 18% | 5% |
| Tristar Producer Services | | 13% | |
| Chevron Texaco | | | 15% |

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**Competition**

The oil and gas industry is highly competitive. Major and independent oil and gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than ours, and staffs and facilities substantially larger than us. The availability of a ready market for our oil and gas production will depend in part on the cost and availability of alternative fuels, the level of consumer demand, the extent of domestic production of oil and gas, the extent of importation of foreign oil and gas, the cost of and proximity to pipelines and other transportation facilities, regulations by state and federal authorities and the cost of complying with applicable environmental regulations.

**Employees**

At March 9, 2007, we had 84 full-time employees in our two administrative offices and two field offices, none of whom is represented by any labor union. In late March, 2007, we expect to close the sale of substantially all of our South Louisiana properties to a private company. Following the sale, we expect to have 74 full-time employees and one field office. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection and well testing.

**Available Information**

Our website address is *www.goodrichpetroleum.com.* We make available, free of charge through the Investor Relations portion of this website, annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the 1934 Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports of beneficial ownership filed pursuant to Section 16(a) of the 1934 Act are also available on our website. Information contained on our website is not part of this report.

**Regulations**

The availability of a ready market for any natural gas and oil production depends upon numerous factors beyond our control. These factors include regulation of natural gas and oil production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of natural gas and oil available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount of natural gas and oil produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies as well.

**Environmental Matters**

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of various permits before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and require remedial measures to mitigate pollution from former and ongoing operations. Failure to comply with these laws and regulations may result in the issuance of administrative, civil and criminal penalties, the assessment of remedial obligations, and the imposition of injunctions to force future compliance.

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The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business. While we believe that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition, there is no assurance that this trend will continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ( CERCLA ), also known as the Superfund law, and analogous state laws impose strict, joint and several liabilities on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or the sites where the release occurred, and those that disposed or arranged for the disposal of hazardous substances released at the site. Persons who are responsible for releases under CERCLA may be subject to joint and several liabilities for remediation costs at the site, and may also be liable for natural resource damages. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We generate materials in the course of our operations that are regulated as hazardous substances. We also may incur liability under the Resource Conservation and Recovery Act, as amended ( RCRA ), which imposes requirements related to the handling and disposal of solid and hazardous wastes. The U.S. Environmental Protection Agency ( EPA ) and various state agencies have limited the approved methods of disposal for certain hazardous and no hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for certain materials generated in the exploration, development or production of oil and gas, we generate petroleum product wastes and ordinary industrial wastes that may be regulated as solid and hazardous wastes.

The Federal Water Pollution Control Act ( Clean Water Act ), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In addition, the Oil Pollution Act of 1990 ( OPA ) imposes a variety of requirements related to the prevention of oil spills into navigable waters. OPA subjects owners of facilities to strict, joint and several liabilities for specified oil removal costs and certain other damages arising from a spill. We believe our operations are in substantial compliance with the Clean Water Act and OPA requirements.

The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe our operations are in substantial compliance with applicable air permitting and control technology requirements.

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and gas properties, establishment of maximum rates of production from oil and gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from our properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Management believes that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition.

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## Item 1A. *Risk Factors*

Our financial and operating results are subject to a number of factors, many of which are not within our control. These factors include the following:

***Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.***

The proved oil and gas reserve information included in this report are estimates. These estimates are based on reports prepared by our independent reserve engineers NSA and were calculated using oil and gas prices as of December 31, 2006. These prices will change and may be lower at the time of production than those prices that prevailed at the end of 2006. Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our pre-tax PV10 Value, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

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***Our future revenues are dependent on the ability to successfully complete drilling activity.***

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- unexpected drilling conditions; pressure or irregularities in formations; equipment failures or accidents;
- adverse weather conditions, including hurricanes;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- title problems;
- compliance with governmental regulations; and
- mechanical difficulties.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain.

In addition, we recently completed drilling our first horizontal well in the Cotton Valley Trend, which is the first well we have drilled in the Cotton Valley Trend utilizing this technique. We have only limited experience drilling horizontal wells and there can be no assurance that this method of drilling will be as effective (or effective at all) as we currently expect it to be.

In addition, higher oil and gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increasing costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

***Natural gas and oil prices are volatile, and low prices have had in the past and could have in the future a material adverse impact on our business.***

Our success will depend on the market prices of oil and natural gas. These market prices tend to fluctuate significantly in response to factors beyond our control. The prices we receive for our crude oil production are based on global market conditions. The general pace of global economic growth, the continued instability in the Middle East and other oil and gas producing regions and actions of the Organization of Petroleum Exporting Countries, or OPEC, and its maintenance of production constraints, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

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Average oil and natural gas prices fluctuated substantially during the three year period ended December 31, 2006. Based on recent history of our industry, fluctuations during the past several years in the demand and supply of crude oil and natural gas have contributed to, and are likely to continue to contribute to, price volatility. Crude oil and natural gas prices are extremely volatile. Any actual or anticipated reduction in crude oil and natural gas prices would depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future. The following table includes high and low for 2006, year-end and current prices; natural gas (price per one million British thermal units or Mmbtu) and crude oil (West Texas Intermediate or WTI):

| | Henry Hub Per Mmbtu |
|---|---|
| January 3, 2006 (high) | $ 9.87 |
| September 29, 2006 (low) | 3.63 |
| December 29, 2006 | 5.50 |
| March 9, 2007 | 7.06 |

| | WTI Per barrel |
|---|---|
| July 14, 2006 (high) | $ 77.03 |
| November 17, 2006 (low) | 55.81 |
| December 29, 2006 | 61.06 |
| March 9, 2007 | 60.05 |

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Reductions in oil and natural gas prices not only reduce revenues and profits, but could also reduce the quantities of reserves that are commercially recoverable. Significant declines in prices could result in non-cash charges to earnings due to impairment. We use derivative financial instruments to hedge a portion of our exposure to changing commodity prices and we have hedged a targeted portion of our anticipated production for 2007.

***Our use of oil and gas price hedging contracts may limit future revenues from price increases and result in significant fluctuations in our net income.***

We use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases.

Our results of operations may be negatively impacted by our financial derivative instruments and fixed price forward sales contracts in the future and these instruments may limit any benefit we would receive from increases in the prices for oil and natural gas. For the year ended December 31, 2006, we realized a loss on settled financial derivatives of $2.1 million. For the years ended December 31, 2005 and 2004, we realized a loss on settled financial derivatives of $18.0 million and $6.2 million, respectively.

For the year ended December 31, 2006, we recognized in earnings an unrealized gain on derivative instruments not qualifying for hedge accounting in the amount of $40.2 million. For financial reporting purposes, this unrealized gain was combined with a $2.1 million realized loss in 2006 resulting in a total unrealized and realized gain on derivative instruments not qualifying for hedge accounting in the amount of $38.1 million for 2006. This gain was recognized because the natural gas hedges were deemed ineffective for 2006, and all previously effective oil hedges were deemed ineffective for the fourth quarter of 2006.

For the year ended December 31, 2005, we recognized in earnings an unrealized loss on derivative instruments not qualifying for hedge accounting in the amount of $27.0 million. For financial reporting purposes, this unrealized loss was combined with a $10.7 million realized loss in 2005 resulting in a total unrealized and realized loss on derivative instruments not qualifying for hedge accounting in the amount of $37.7 million in 2005. For the year ended December 31, 2004, we recognized in earnings an unrealized gain on derivative instruments in the amount of $2.3 million. This loss and gain were recognized because the natural gas hedges were deemed to be ineffective for 2005, and for the fourth quarter of 2004, and accordingly, the changes in fair value of such hedges could no longer be reflected in other comprehensive income, a component of stockholders equity.

To the extent that the hedges are not deemed to be effective in the future, we will likewise be exposed to volatility in earnings resulting from changes in the fair value of our hedges. See Note 8 Hedging Activities to our consolidated financial statements for further discussion.

***Delays in development or production curtailment affecting our material properties may adversely affect our financial position and results of operations.***

The size of our operations and our capital expenditure budget limits the number of wells that we can develop in any given year. Complications in the development of any single material well may result in a material adverse affect on our financial condition and results of operations. In addition, a relatively small number of wells contribute a substantial portion of our production. If we were to experience operational problems resulting in the curtailment of production in any of these wells, our total production levels would be adversely affected, which would have a material adverse affect on our financial condition and results of operations.

***Because our operations require significant capital expenditures, we may not have the funds available to replace reserves, maintain production or maintain interests in our properties.***

We must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. Historically, we have paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Our revenues or cash flows could be reduced because of lower oil and natural gas prices or for other reasons. If our revenues or cash flows decrease, we may not have the funds available to replace reserves or maintain production at current levels. If this occurs, our production will decline over time. Other sources of financing may not be available to us if our cash flows from operations are not sufficient to fund our capital expenditure requirements. Where we are not the majority owner or operator of an oil and gas property, such as the Lafitte field, we may have no control over the timing or amount of capital expenditures associated with the particular property. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

***We may have difficulty financing our planned growth.***

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our drilling program. In the future, we expect that we will require additional financing, in addition to cash generated from operations, to fund planned growth. We cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

***If we are not able to replace reserves, we may not be able to sustain production at present levels.***

Our future success depends largely upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. In addition, approximately 57% of our total estimated proved reserves by volume at December 31, 2006, were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

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***We may incur substantial impairment writedowns.***

If management s estimates of the recoverable reserves on a property are revised downward or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management s estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, impairment and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units estimated reserves, future cash flows and fair value. For the years ended December 31, 2006, and 2005, we recorded impairments of $24.8 million and $0.3 million, respectively. We did not record an impairment loss for the year ended December 31, 2004.

Management s assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

***A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a geographic area.***

Approximately 84% of our estimated proved reserves at December 31, 2006, and a similar percentage of our production during 2006 were associated with our Cotton Valley Trend. We have under contract to sell substantially all of our South Louisiana properties to a private company, with an anticipated closing date in late March 2007. See Note 12 Acquisitions and Divestitures to our consolidated financial statements. Accordingly, if the level of production from the remaining properties substantially declines, it could have a material adverse effect on our overall production level and our revenue.

***The oil and gas business involves many uncertainties, economic risks and operating risks that can prevent us from realizing profits and can cause substantial losses.***

Our oil and gas operations are subject to the economic risks typically associated with exploration, development and production activities, including the necessity of significant expenditures to locate and acquire properties and to drill exploratory wells. In conducting exploration and development activities, the presence of unanticipated pressure or irregularities in formations, miscalculations or accidents may cause our exploration, development and production activities to be unsuccessful. This could result in a total loss of our investment in a particular property. If exploration efforts are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs would be charged against earnings as impairments. In addition, the cost and timing of drilling, completing and operating wells is often uncertain.

The nature of the oil and gas business involves certain operating hazards such as well blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, formations with abnormal pressures, pollution, releases of toxic gas and other environmental hazards and risks. Any of these operating hazards could result in

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substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties. Additionally, some of our oil and gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. In accordance with customary industry practices, we maintain insurance against some, but not all, of such risks and losses. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

***Our debt instruments impose restrictions on us that may affect our ability to successfully operate our business.***

Our senior credit facility contains customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our credit facility. As of December 31, 2006, we were in compliance with all the financial covenants of our credit facility. These restrictions may make it difficult for us to successfully execute our business strategy or to compete in our industry with companies not similarly restricted.

***We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.***

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities that we created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. The incurrence of an unexpected liability could have a material adverse effect on our financial position and results of operations.

***We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.***

Development, production and sale of natural gas and oil in the U.S. are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- bonds for ownership, development and production of oil and gas properties;
- reports concerning operations; and

taxation.

In addition, our operations are subject to stringent federal, state and local environmental laws and regulations governing the discharge of materials into the environment and environmental protection. Governmental authorities enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of our operations. There is inherent risk of incurring significant environmental costs and liabilities in our business. Joint and several strict liabilities may be incurred in connection with discharges or releases of petroleum hydrocarbons and wastes on, under or from our properties and from facilities where our wastes have been taken for disposal. Private parties affected by such discharges or releases may also have the right to pursue legal actions to enforce compliance as well as seek damages for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly requirements could have a material adverse effect on our business.

***Competition in the oil and gas industry is intense, and we are smaller and have a more limited operating history than some of our competitors.***

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources than us. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

***Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.***

Our success will depend on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

***Some of our operations are exposed to the additional risk of tropical weather disturbances.***

Some of our production and reserves were located in South Louisiana as of December 31, 2006. Operations in this area are subject to tropical weather disturbances. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, Hurricanes Katrina and Rita in August and September of 2005, respectively, impacted our South Louisiana operations. In January 2007, we announced the sale of substantially all of our properties in South Louisiana to a private company. See Note 12 Acquisitions and Divestitures to our consolidated financial statements. If the sale closes as expected, our exposure to tropical weather disturbances will be significantly reduced by the end of the first quarter 2007.

Losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations. Hurricane Katrina and Rita damage costs in excess of our insurance coverage resulted in a $1.7 million loss for 2006. The loss is included in Lease Operating Expenses on our consolidated financial statements. In 2007, we expect to receive $2.5 million from our insurance provider for Hurricane Katrina damage costs. The receivable is included in Accounts Receivable Trade and other, net on our consolidated financial statements.

***We have previously identified a material weakness in our internal controls over financial reporting and cannot assure you that we will not again identify a material weakness in the future.***

As previously reported in our quarterly report on Form 10-Q for the quarter ended March 31, 2006, a material weakness was identified in our internal control over financial reporting with respect to recording the fair

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value of all outstanding derivatives. The Public Company Accounting Oversight Board s Auditing Standard No. 2 defines a material weakness as a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

In order to remediate the material weakness, we implemented changes in our internal control over financial reporting during the quarter ended June 30, 2006. Specifically, we now automatically receive a mark to market valuation from our existing counterparties for all outstanding derivatives. For any new contracts entered into with a new counterparty, we will concurrently request this automatic distribution. We also added another layer of review for the fair value calculation prior to review by the Chief Financial Officer.

Our management believes that these additional policies and procedures have enhanced our internal control over financial reporting relating to the determination and review of fair value calculations on outstanding derivatives. Our management also believes that, as a result of these measures described above, the material weakness was remediated and that our internal control over financial reporting is effective as of June 30, 2006, September 30, 2006, and December 31, 2006.

***Terrorist attacks or similar hostilities may adversely impact our results of operations.***

The impact that future terrorist attacks or regional hostilities (particularly in the Middle East) may have on the energy industry in general, and on us in particular, is unknown. Uncertainty surrounding military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. Moreover, we have incurred additional costs since the terrorist attacks of September 11, 2001 to safeguard certain of our assets and we may be required to incur significant additional costs in the future.

The terrorist attacks on September 11, 2001, and the changes in the insurance markets attributable to such attacks have made certain types of insurance more difficult for us to obtain. There can be no assurance that insurance will be available to us without significant additional costs. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

**Item 1B.** ***Unresolved Staff Comments***

None.

**Item 3.** ***Legal Proceedings***

In the third quarter of 2004, we recognized a non-recurring gain in the amount of $2.1 million, reflecting the proceeds of a successful litigation judgment. We commenced the litigation as plaintiff in February 2000 against the operator of a South Louisiana property which was jointly acquired by us and the defendant in September 1999. The judgment provided for recovery of our damages and a portion of our attorneys fees as well as interest calculated on our damages.

We are party to additional lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our financial position or results of operations.

**Item 4.** ***Submission of Matters to a Vote of Security Holders***

None.

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## PART II

### Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

**Market Price of Our Common Stock**

Our common stock is traded on the New York Stock Exchange under the symbol GDP .

At March 9, 2007, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,521 with 28,288,838 shares outstanding. High and low sales prices for our common stock for each quarter during the calendar years 2006 and 2005 are as follows:

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | High | Low | High | Low |
| March 31 | $ 29.60 | $ 23.58 | $ 25.39 | $ 14.61 |
| June 30 | 28.95 | 22.59 | 23.36 | 14.74 |
| September 30 | 35.95 | 26.34 | 24.80 | 19.00 |
| December 31 | 44.57 | 25.21 | 26.29 | 19.25 |

**Dividends**

We have neither declared nor paid any cash dividends on our common stock and do not anticipate declaring any dividends in the foreseeable future. We expect to retain our cash for the operation and expansion of our business, including exploration, development and production activities. In addition, our senior bank credit facility contains restrictions on the payment of dividends to the holders of common stock. For additional information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

**Issuer Repurchases of Equity Securities**

We made no repurchases of our common stock for the year ended December 31, 2006.

For information on securities authorized for issuance under our equity compensation plans, see Item 12 Security Ownership of Certain Beneficial Owners and Management.

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**Item 6.** ***Selected Financial Data***

The following table sets forth our selected financial data and other operating information. The selected consolidated financial data in the table are derived from our consolidated financial statements. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

**Statement of Operations Data:**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2006** | **2005** | **2004** | **2003** | **2002** |
| | (In thousands, except per share data) | | | | |
| Revenues | | | | | |
| Oil and gas revenues | $ 113,696 | $ 68,387 | $ 44,861 | $ 31,663 | $ 18,502 |
| Other | 2,458 | 1,016 | 151 | 477 | 131 |
| | 116,154 | 69,403 | 45,012 | 32,140 | 18,633 |
| Operating Expenses | | | | | |
| Lease operating expense | 21,877 | 9,931 | 7,402 | 6,099 | 7,523 |
| Production taxes | 5,993 | 4,053 | 3,105 | 2,288 | 1,642 |
| Transportation | 4,013 | 558 | | | |
| Depletion, depreciation and amortization | 52,642 | 25,563 | 11,562 | 8,996 | 7,023 |
| Exploration | 15,058 | 6,867 | 4,426 | 2,249 | 1,019 |
| Impairment of oil and gas properties | 24,790 | 340 | | 335 | 342 |
| General and administrative | 17,223 | 8,622 | 5,821 | 5,314 | 4,468 |
| (Gain) loss on sale of assets | (23) | (235) | (50) | 66 | (2,941) |
| Other | 1,709 | 512 | | | |
| | 143,282 | 56,211 | 32,266 | 25,347 | 19,076 |
| Operating income (loss) | (27,128) | 13,192 | 12,746 | 6,793 | (443) |
| Other income (expense): | | | | | |
| Interest expense | (7,845) | (2,359) | (1,110) | (1,051) | (985) |
| Gain (loss) on derivatives not qualifying for hedge accounting | 38,128 | (37,680) | 2,317 | | |
| Loss on early extinguishment of debt | (612) | | | | |
| Gain on litigation judgment | | | 2,118 | | |
| | 29,671 | (40,039) | 3,325 | (1,051) | (985) |
| Income (loss) from continuing operations before income taxes | 2,543 | (26,847) | 16,071 | 5,742 | (1,428) |
| Income tax (expense) benefit | (904) | 9,397 | 1,707 | (2,016) | 496 |
| Income (loss) from continuing operations | 1,639 | (17,450) | 17,778 | 3,726 | (932) |
| Discontinued operations including gain on sale, net of income taxes | | | 749 | 196 | (19) |

| | | | | | |
|---|---|---|---|---|---|
| Income (loss) before cumulative effect of change in accounting principle | 1,639 | (17,450) | 18,527 | 3,922 | (951) |
| Cumulative effect of change in accounting principle, net of income taxes | | | | (205) | |
| Net income (loss) | 1,639 | (17,450) | 18,527 | 3,717 | (951) |
| Preferred stock dividends | 6,016 | 755 | 633 | 633 | 640 |
| Preferred stock redemption premium | 1,545 | | | | |
| Net income (loss) applicable to common stock | $ (5,922) | $ (18,205) | $ 17,894 | $ 3,084 | $ (1,591) |
| Net income (loss) per common share from continuing operations | | | | | |
| Basic | $ (0.24) | $ (0.75) | $ 0.91 | $ 0.21 | $ (0.05) |
| Diluted | $ (0.24) | $ (0.75) | $ 0.87 | $ 0.18 | $ (0.05) |
| Weighted average number of common shares outstanding: | | | | | |
| Basic | 24,948 | 23,333 | 19,552 | 18,064 | 17,908 |
| Diluted | 25,412 | 23,333 | 20,347 | 20,482 | 17,908 |

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| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| Balance Sheet Data: | | | | | |
| Total assets | $ 479,264 | $ 296,526 | $ 127,977 | $ 89,182 | $ 78,567 |
| Total long term debt | 201,500 | 30,000 | 27,000 | 20,000 | 18,500 |
| Stockholders equity | 205,133 | 181,589 | 65,307 | 48,059 | 44,607 |

**Item 7.** ***Management s Discussion and Analysis of Financial Condition and Results of Operation*****s**

**Forward-Looking Statements**

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company s control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to:

planned capital expenditures,

future drilling activity,

our financial condition,

business strategy,

the market prices of oil and gas,

economic and competitive conditions,

legislative and regulatory changes and

financial market conditions.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Although from time to time we make use of futures contracts, swaps, costless collars and fixed-price physical contracts to mitigate risk, fluctuations in oil and gas prices, or a prolonged continuation of low prices may substantially adversely affect the Company s financial position, results of operations and cash flows.

**Overview**

We are an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the Cotton Valley Trend of East Texas and Northwest Louisiana. We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined in the Financial Accounting Standards Board ( FASB ) Statement of Financial Accounting Standards ( SFAS ) No. 131, *Disclosures about Segments of an Enterprise and Related Information* .

We seek to increase shareholder value by growing our oil and gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and gas reserves and production, on a cost-effective basis, are the most important indicators of performance success for an independent oil and gas company.

Management strives to increase our oil and gas reserves, production and cash flow through exploration and exploitation activities. We develop an annual capital expenditure budget which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, when establishing our capital expenditure budget.

We place primary emphasis on our internally generated operating cash flow in managing our business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in our Statement of Cash Flows. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income.

Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects, the volume and timing of our production, as well as commodity prices for oil and gas. Such pricing factors are largely beyond our control, however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

**Cotton Valley Trend: Expanding Acreage Position and Active Development Drilling Program**

Our relatively low risk development drilling program in the Cotton Valley Trend is primarily centered in and around Rusk, Panola, Angelina, Nacogdoches, Cherokee, Harrison, Smith and Upshur Counties, Texas and DeSoto, Caddo and Bienville Parishes, Louisiana. We continue to build our acreage position in the Cotton Valley trend and now hold approximately 180,000 gross acres as of February 15, 2007. As of year end, we have drilled and/or logged a cumulative total of 156 Cotton Valley wells with a success rate slightly in excess of 99%. Our net production volumes from our Cotton Valley Trend wells aggregated approximately 29,964 Mcfe per day in 2006, or approximately 69% of our total oil and gas production in the period.

*Acquisition of Remaining Interests in Dirgin-Beckville Area of Cotton Valley Trend*

In early December 2006, we acquired a 14.5% working interest in 22 wells and approximately 3,300 gross (500 net) acres within the Dirgin-Beckville field in the Cotton Valley Trend from a private company for $6.1 million. With the additional interest we now own an approximate 99% working interest in 52 wells and 12,600 gross acres in this field.

*Farmout on 21,200 acres in Northwest Louisiana*

In November 2006, we announced a definitive farmout agreement covering 21,200 gross acres in 33 sections (16,000 net acres), in the Alabama Bend field of Bienville Parish, Louisiana. The Company has farmed in the right to explore for natural gas and oil at no upfront cost. The Company will own a 100% working interest in the initial well drilled in each of the 33 sections and the Farmor shall have the right to participate up to 50% for future wells drilled. To maintain the rights of the entire acreage block, we must commence drilling operations on one well every 90 days from completion date of the previous well.

*Acquisition of Acreage in Angelina River Play in Nacogdoches and Angelina Counties, Texas*

On February 7, 2007, we announced the acquisition of drilling and development rights in approximately 16,800 gross acres (8,380 net acres) in the Angelina River play, on trend with our existing acreage in Nacogdoches and Angelina Counties, Texas. We acquired a 60% working interest in the acreage and will operate the joint venture. The acquisition was completed in two separate transactions. In the initial transaction, we acquired a 40% interest for $2.0 million from a private company. We also agreed to carry the private company for a 20% interest in the drilling of five wells. In the second transaction, we are purchasing the remaining 20% interest in the acreage in a like-kind exchange for our 30% interest in the Mary Blevins field in Smith County, Texas.

**South Louisiana Operations: 2007 Sale of Assets**

On January 12, 2007, the Company and Malloy Energy Company, LLC ( Malloy Energy ) entered into a Purchase and Sale Agreement with a private company for the sale of substantially all of the company s oil and gas properties in South Louisiana. The total sales price for the Company s interest in the oil and gas properties was approximately $100 million, effective July 1, 2006. The total sales price for Malloy Energy s interests in these properties was approximately $30 million. See Note 11 Related Party Transactions to our consolidated financial statements for additional information regarding Malloy Energy. Both the Company and Malloy Energy s total consideration will be reduced by an amount equal to its proportionate share of the greater of $20 million or normal closing adjustments. We expect the adjusted sales price for the Company s interest to be approximately $80 million. The effective date of the transaction was July 1, 2006 and the closing date of the Purchase and Sale Agreement is targeted for late March, 2007. Had we completed this transaction at the end of 2006, our proved reserves would have been reduced by approximately 31,700 MMcfe. Average daily production for these properties for the fiscal year-ending December 31, 2006, was approximately 12,790 Mcfe or about 30% of the Company s total production for 2006. This sale will allow us to focus the majority of our efforts on the development of our Cotton Valley Trend acreage, as well as reduce operating costs going forward.

**Overview of 2006 Results**

2006 Financial and operating highlights include:

- We increased production 82% over 2005. Production averaged 43.4 MMcfe/d compared to 23.8 MMcfe/d in 2005.

- Our 2006 oil and gas revenues totaled $113.7 million compared to $68.4 million in 2005, a 66 percent increase.

- Net cash provided by operating activities increased $19.6 million from 2005, to $65.1 million.

- Estimated proved reserves grew 19 percent to approximately 206.2 Bcfe (approximately 187.0 Bcf of natural gas and 3.2 MMBbls of oil and condensate), with a pre-tax present value of future net cash flows, discounted at 10%, of $214.2 million and an after-tax present value of discounted future net cash flows of $200.3 million.

- Capital expenditures totaled $269.4 million in 2006, versus $164.6 million in 2005.

- As operator, we successfully drilled, completed and placed in production 101 wells during calendar year 2006.

- We issued $175.0 million in 3.25% convertible senior notes due 2026, completely paying off our Second Lien Term Loan and substantially reducing our bank revolver debt.

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| Summary Operating Information: | Year Ended December 31, | | | | Year Ended December 31, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2006 | 2005 | Variance | | 2005 | 2004 | Variance | |
| | (in thousands, except for price data) | | | | | | | |
| **Revenues:** | | | | | | | | |
| Natural Gas | $ 86,621 | $ 53,746 | $ 32,875 | 61% | $ 53,746 | $ 31,315 | $ 22,431 | 72% |
| Oil and condensate | 30,619 | 21,884 | 8,735 | 40% | 21,884 | 19,714 | 2,170 | 11% |
| Effect of settled derivatives gas | | | | | | (1,830) | 1,830 | 100% |
| Effect of settled derivatives oil | (3,544) | (7,243) | 3,699 | 51% | (7,243) | (4,338) | (2,905) | (67)% |
| Natural gas, oil and condensate | 113,696 | 68,387 | 45,309 | 66% | 68,387 | 44,861 | 23,526 | 52% |
| Operating revenues | 116,154 | 69,403 | 46,751 | 67% | 69,403 | 45,012 | 24,391 | 54% |
| Operating expenses | 143,282 | 56,211 | 87,071 | 155% | 56,211 | 32,266 | 23,945 | 74% |
| Operating income | (27,128) | 13,192 | 40,320 | 306% | 13,192 | 12,746 | 446 | 3% |
| Net Income (loss) applicable to common stock | $ (5,922) | $ (18,205) | $ 12,283 | 67% | $ (18,205) | $ 17,894 | $ (36,099) | (202)% |
| **Net Production:** | | | | | | | | |
| Natural gas (MMcf) | 13,001 | 6,237 | 6,764 | 108% | 6,237 | 4,818 | 1,419 | 29% |
| Oil and gas condensate (MBbls) | 474 | 408 | 66 | 16% | 408 | 475 | (67) | (14)% |
| Total (Mmcfe) | 15,843 | 8,686 | 7,157 | 82% | 8,686 | 7,669 | 1,107 | 13% |
| Average daily production (Mmcfe/d) | 43,406 | 23,797 | 19,609 | 82% | 23,797 | 20,954 | 2,843 | 14% |
| **Average Realized Sales price Per Unit:** | | | | | | | | |
| Natural gas (per Mcf) unhedged | $ 6.66 | $ 8.62 | $ (1.96) | (23)% | $ 8.62 | $ 6.50 | $ 2.12 | 33% |
| Effect of settled derivatives (per Mcf) | | | | | | (0.38) | 0.38 | (100)% |
| Average realized price (per Mcf) | 6.66 | 8.62 | (1.96) | (23)% | 8.62 | 6.12 | 2.50 | 41% |
| Oil and condensate (per Bbl) unhedged | 64.60 | 57.64 | 6.96 | 12% | 57.64 | 41.48 | 16.16 | 39% |
| Effect of settled derivatives (per Bbl) | (7.48) | (27.73) | 20.25 | 73% | (27.73) | (9.13) | (18.60) | (204)% |
| Average realized price (per Bbl) | 57.12 | 29.91 | 27.21 | 91% | 29.91 | 32.35 | 2.44 | 8% |
| Average realized price (per Mcfe) | $ 7.18 | $ 7.88 | $ (0.70) | (9)% | $ 7.88 | $ 5.85 | $ 2.03 | 35% |

**Results of Operations**

***Operating Income***

*Year ended December 31, 2006 compared to year ended December 31, 2005*

Operating revenues increased 67% or $46.8 million to a total of $116.2 million in 2006 compared to 2005. The increase resulted from an 82% increase in production volumes. The drilling, completion and placing into production of 101 operated wells in the Cotton Valley Trend led to natural gas production more than doubling in 2006. Oil production was returned to mid 2005 levels as production was restored from hurricane shut-ins. Partially offsetting increases from production gains, the average realized price for natural gas fell in 2006 by 23% to $6.66 per Mcf. Realized oil prices were strong in 2006, increasing 91% to $57.12 per Bbl.

*Year ended December 31, 2005 compared to year ended December 31, 2004*

Operating revenues increased 54% or $24.4 million in 2005 compared to 2004. This increase resulted from a 13% increase in oil and gas production volumes, due to a substantial increase in Cotton Valley Trend production, as well as higher average oil and gas prices. Partially offsetting this increase was a decline in South Louisiana production, due to natural decline and the effects of shut-ins due to the hurricanes in the third and fourth quarters of 2005.

| | Year Ended December 31, | | | | Year Ended December 31, | | | |
|---|---|---|---|---|---|---|---|---|
| **Operating Expenses per Mcfe** | **2006** | **2005** | **Variance** | | **2005** | **2004** | **Variance** | |
| Lease operating expense | $ 1.38 | $ 1.14 | $ 0.24 | 21% | $ 1.14 | $ 0.97 | 0.17 | 17% |
| Production taxes | 0.38 | 0.47 | (0.09) | (19)% | 0.47 | 0.40 | 0.07 | 18% |
| Transportation | 0.25 | 0.06 | 0.19 | 317% | 0.06 | | 0.06 | |
| Depreciation, depletion and Amortization | 3.32 | 2.94 | 0.38 | 13% | 2.94 | 1.51 | 1.43 | 95% |
| Exploration | 0.95 | 0.79 | 0.16 | 20% | 0.79 | 0.58 | 0.21 | 37% |
| Impairment of oil and gas properties | 1.56 | 0.04 | 1.52 | | 0.04 | | 0.04 | |
| General and administrative | 1.09 | 0.99 | 0.10 | 10% | 0.99 | 0.76 | 0.23 | 30% |

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***Operating Expenses***

*Year ended December 31, 2006 compared to year ended December 31, 2005*

Lease operating expense (LOE) was $21.9 million for 2006 compared to $9.9 million for 2005. Given the rapid pace of our development program in the Cotton Valley Trend in 2006, we experienced significant increases in two major components of LOE, salt water disposal costs ($4.1 million) and compressor rental expense ($2.9 million). With the planned installation of our low pressure gathering system in this region, along with the sale of the South Louisiana properties, we expect to see a decline in the per unit LOE charges in 2007. Additionally, Hurricanes Katrina and Rita damage costs in excess of our insurance coverage resulted in a $1.7 million net expense for 2006. This net expenditure over insurance reimbursement represents a $0.10 increase in the LOE per Mcfe. Higher workover activity also contributed to a higher cost per Mcfe in 2006. The majority of this activity occurred during the fourth quarter.

Production taxes were $6.0 million for 2006 versus $4.1 million in 2005. The reduction in production taxes per Mcfe resulted from rebates approved by the State of Texas of $1.3 million. These severance tax rebates relate to a number of our wells which have been approved as high cost tight gas sand wells, allowing us to pay a lower severance tax rate for up to 10 years following certification by the state.

Transportation expense was $4.0 million for 2006 compared to $0.6 million for 2005. The significant increase in transportation expense was due to the requirement for longer transportation segments in our Cotton Valley Trend properties versus our properties in South Louisiana. As our volumes from the Cotton Valley Trend expanded over 181% during 2006, our transportation expense increased accordingly.

Depletion, depreciation and amortization expense ( DD&A ) was $52.6 million for the year ended December 31, 2006, versus $25.6 million for the year ended December 31, 2005, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

Exploration expense for the year ended December 31, 2006, was $15.1 million versus $6.9 million for the year ended December 31, 2005. In 2006, we recorded $7.9 million in dry hole costs for the Bayou Boullion exploratory well. Leasehold amortization was $5.5 million, versus $3.3 million in 2005.

We recorded an impairment expense of $24.8 million in the year ended December 31, 2006, all of it being determined in conjunction with the receipt of the independent engineer s final report on reserves as of that date. Of the total expense of $24.8 million, $14.9 million related primarily to two South Louisiana fields (St. Gabriel at $13.0 million and Plumb Bob at $1.9 million), $8.4 million related to two fields in East Texas which were not a part of the Company s primary Cotton Valley Trend acreage position, and the remaining $1.5 million was spread among several minor properties. In the St. Gabriel field, although significant reserves were initially estimated to be present and recoverable when the Gueymard #1 well was drilled in the first quarter of 2006, mechanical problems experienced during completion operations resulted in the initial production from this well being delayed until December 2006. Once on production, and following receipt of the year end reserve report, we determined that the ultimate reserves attributed to this well were insufficient to justify the expenses associated with the drilling and completion of the well, therefore the impairment was taken at that date.

General and administrative ( G&A ) expenses increased to $17.2 million for the year ended December 31, 2006, from $8.6 million for the year ended December 31, 2005. Stock-based compensation, which consists of the amortization of restricted stock awards and expense associated with our stock option plan, increased to $6.0 million for the year ended December 31, 2006, compared to $1.4 million in 2005. We adopted SFAS 123R on January 1, 2006. SFAS 123R requires new, modified and unvested share-based payment transactions with employees to be measured at fair value and recognized as compensation expense over the requisite service period. See Note 2 Stock-Based Compensation to our consolidated financial statements for additional information.

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*Year ended December 31, 2005 compared to year ended December 31, 2004*

Lease operating expense was $9.9 million for the year ended December 31, 2005 versus $7.4 million for the year ended December 31, 2004, with the increase due to an increase in production volumes as well as an increase in hurricane related operating expenses in South Louisiana.

Production taxes were $4.1 million for the year ended December 31, 2005 compared to $3.1 million for the year ended December 31, 2004, due to an increase in production volumes and product prices.

DD&A was $25.6 million for the year ended December 31, 2005, versus $11.6 million for the year ended December 31, 2004, with the increase due to higher production volumes and higher DD&A rates. The higher rates are a result of an increase in capitalized development costs.

Exploration expense for the year ended December 31, 2005 was $6.9 million versus $4.4 million for the year ended December 31, 2004, primarily due to increased dry hole costs from an exploratory well drilled in East Baton Rouge Parish, Louisiana, and higher non-producing leasehold amortization expense associated with the expansion of our Cotton Valley Trend acreage position.

We recorded an impairment expense of $0.3 million in the recorded value of one property for the year ended December 31, 2005, due to sooner than anticipated depletion of reserves.

G&A increased to $8.6 million for the year ended December 31, 2005, from $5.8 million for the year ended December 31, 2004. This increase was primarily due to higher compensation related costs due to an approximate 25% increase in the number of employees in 2005 and professional fees related to the implementation of the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. Stock-based compensation, which consists of the amortization of restricted stock awards, increased to $1.1 million for the year ended December 31, 2005, compared to $0.6 million for the comparable period in 2004 due to the vesting of awards previously granted.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (in thousands) | |
| **Other income (expense):** | | | |
| Interest Expense | $ (7,845) | $ (2,359) | $ (1,110) |
| Gain (loss) on derivatives not qualifying for hedge accounting | 38,128 | (37,680) | 2,317 |
| Loss on early extinguishment of debt | (612) | | |
| Gain on litigation judgement | | | 2,118 |
| Income from discontinued operations | | | 749 |
| Income tax (expense) benefit | (904) | 9,397 | 1,707 |
| Average total borrowings | $ 99,542 | $ 30,417 | $ 22,958 |
| Weighted average interest rate | 7.5% | 7.0% | 3.8% |

***Other Income (Expense)***

*Year ended December 31, 2006 compared to December 31, 2005*

Interest expense was $7.8 million for 2006, compared to $2.4 million for 2005, with the increase primarily attributable to a higher level of average borrowings in 2006.

Gain on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges for the entire year and for our ineffective oil hedges for the fourth quarter, and amounted to $38.1 million for the year ended December 31, 2006, compared to a loss of $37.7 million for the year ended December 31, 2005. The gain in 2006 includes an unrealized gain of $40.2 million in the mark to market value of our ineffective gas and oil hedges and a realized loss of $2.1 million for the effect of settled derivatives on our ineffective gas and oil hedges. Our natural gas hedges were ineffective again in 2006, and certain oil hedges were deemed ineffective in the fourth quarter of 2006 thereby rendering all of our commodity derivatives ineffective. For these ineffective hedges, we are required to reflect the changes in the fair value of the hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. As applied to our hedging program, there must be a high degree of correlation between the actual prices received and the hedge prices in order to justify treatment as cash flow hedges pursuant to SFAS 133. We perform historical correlation analyses of the actual and hedged prices over an extended period of time. In the fourth quarter of 2006, we determined that certain of our oil hedges which had previously been effective, fell short of the effectiveness guidelines to be accounted for as cash flow hedges. To the extent that our hedges are deemed to be ineffective in the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

We fully paid off our Second Lien Term loan in early December 2006 with the proceeds of the 3.25% convertible senior notes offering. In the fourth quarter of 2006, we wrote off remaining deferred loan financing costs of $0.6 million which resulted from the initial funding of this loan and a subsequent amendment.

Income tax expense of $0.9 million which was non-cash, represents 35.5% of the pre-tax income in 2006. Income tax benefit of $9.4 million in 2005 represents 35% of pre-tax loss in 2005. In 2004, a revision in the deferred tax valuation allowance of $7.3 million was recorded based on the anticipated reversal of temporary differences in 2004. The net deferred tax asset as of December 31, 2006, is expected to be realized based upon expected utilization of tax net operating loss carryforwards and the projected reversal of temporary differences.

*Year ended December 31, 2005 compared to year ended December 31 2004*

Interest expense was $2.4 million for the year ended December 31, 2005, compared to $1.1 million for the year ended December 31, 2004, with the increase primarily attributable to a higher level of average borrowings in 2005 and a higher total interest rate.

Loss on derivatives not qualifying for hedge accounting relates to our ineffective gas hedges and amounted to $37.7 million for the year ended December 31, 2005, compared to a gain of $2.3 million for the year ended December 31, 2004. The loss in 2005 includes a realized loss of $10.7 million for the effect of settled derivatives on our ineffective gas hedges and an unrealized loss of $27.0 million for the changes in fair value of our ineffective gas hedges. Since our natural gas hedges were deemed ineffective, beginning in the fourth quarter of 2004, we have been required to reflect the changes in the fair value of our natural gas hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. In the fourth quarter of 2004, we initially determined that our gas hedges fell short of the effectiveness guidelines to be accounted for as cash flow hedges and, likewise, made the same determination in each of the four quarters of 2005.

Gain on litigation judgment of $2.1 million for the year ended December 31, 2004, resulted from the final judgment ordered by the trial judge in our favor our litigation against the operator of the Lafitte field. See Item 3. Legal Proceedings.

Income taxes from continuing operations were benefits of $9.4 million and $1.7 million for the years ended December 31, 2005 and 2004, respectively, representing 35% of the pre-tax loss in 2005, and the $7.3 million revision of the deferred tax valuation allowance in 2004.

Income from discontinued operations, net of income taxes, was $0.7 million for the year ended December 31, 2004, consisted largely of the pre-tax gain realized on the sale of our operated interests in the Marholl and Sean Andrew fields, along with our non-operated interests in the Ackerly field, all of which were located in West Texas.

*Liquidity and Capital Resources*

Our principal requirements for capital are to fund our exploration and development activities and to satisfy our contractual obligations. These obligations include the repayment of debt and any amounts owing during the period relating to our hedging positions. Our uses of capital include the following:

- Drilling and completing new natural gas and oil wells;
- Constructing and installing new production infrastructure;

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Acquiring and maintaining our lease position, specifically in the Cotton Valley Trend;

Plugging and abandoning depleted or uneconomic wells.

Our capital budget for 2007 is $275 million. We continue to evaluate our capital budget throughout the year.

*Future commitments*

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2006. See Note 4, Long-Term Debt and Note 10, Commitments and Contingencies to our consolidated financial statements for additional information.

**Payments due by Period**

| | Note | Total | 2007 | 2008 | 2009 | 2010 | 2011 | After 2011 |
|---|---|---|---|---|---|---|---|---|
| | | | | (in thousands) | | | | |
| **Contractual Obligations** | | | | | | | | |
| Long term debt (1) | 4 | $ 201,500 | $ | $ | $ | $ 26,500 | $ 175,000 | |
| Operating leases for office space | 10 | 1,992 | 701 | 710 | 491 | 48 | 42 | |
| Drilling rig commitments | 10 | 80,247 | 45,983 | 24,956 | 9,308 | | | |
| Transportation contracts | 10 | 2,159 | 758 | 540 | 540 | 321 | | |
| Total contractual obligations (2) | | $ 285,898 | $ 47,442 | $ 26,206 | $ 10,339 | $ 26,869 | $ 175,042 | $ |

(1) The $175.0 million convertible senior notes have a provision at the end of years 5, 10 and 15, for the investors to demand payment on these dates; the first such date is December 1, 2011.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $9.6 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3, Asset Retirement Obligation to our consolidated financial statements.

*Capital Resources*

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations, borrowings under our revolving bank credit facility and the proceeds from the 2007 sale of South Louisiana properties. In the future, we may also access public markets to issue additional debt and/or equity securities.

At December 31, 2006, we had $123.5 million of excess borrowing capacity under our revolving bank credit facility. Our primary sources of cash during 2006 were from funds generated from operations, bank borrowings and proceeds received from the issuance of $175.0 million of convertible notes in December 2006. Cash was used primarily to fund exploration and development expenditures. During 2006 we made aggregate cash payments of $7.3 million for interest. There were no payments made in 2006 for federal income taxes. The table below summarizes the sources of cash during 2006, 2005 and 2004:

| | Year Ended December 31, | | | Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| **Cash flow statement information:** | **2006** | **2005** | **Variance** | **2005** | **2004** | **Variance** |
| | | | (in thousands) | | | |
| **Net cash:** | | | | | | |
| Provided by operating activities | $ 65,133 | $ 45,562 | $ 19,571 | $ 45,562 | $ 41,028 | $ 4,534 |
| Used in investing activities | (258,737) | (163,571) | (95,166) | (163,571) | (45,414) | (118,157) |
| Provided by financing activities | 179,946 | 134,402 | 45,544 | 134,402 | 6,346 | 128,056 |
| Increase (decrease) in cash and cash equivalents | $ (13,658) | $ 16,393 | $ (30,051) | $ 16,393 | $ 1,960 | $ 14,433 |

At December 31, 2006, we had a working capital deficit of $22.2 million and long-term debt of $201.5 million. The working capital deficit was due to the typical timing difference between the expenditure of funds and accruals resulting from drilling and completion activities.

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***Cash Flows***

*Year ended December 31, 2006 compared to year ended December 31, 2005*

*Operating activities*. Cash flow from operations is dependent upon our ability to increase production through development, exploration and acquisition activities and the price of oil and natural gas. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities increased to $65.1 million, up 43% from $45.6 million in 2005. As previously mentioned, the 67% increase in operating revenues due to higher production volumes drove the increased cash flow in 2006. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases of $4.9 million and $13.2 million for the years ended December 31, 2006 and 2005, respectively.

*Investing activities*. Net cash used in investing activities was $258.7 million for the year ended December 31, 2006, compared to $163.6 million for 2005. Of the $258.7 million, approximately $211.0 million was spent for drilling and completion activities in the Cotton Valley Trend, versus $139.9 million in 2005.

*Financing activities.* Net cash provided by financing activities was $179.9 million in 2006 versus $134.4 million in 2005. The majority of our net financing cash flows came from the $175.0 million in convertible note proceeds, and the $29.0 million in convertible preferred proceeds received in 2006.

*Year ended December 31, 2005 compared to year ended December 31, 2004*

*Operating activities*. Net cash provided by operating activities increased to $45.6 million, up 11% from $41.0 million in 2004. The increases in 2005 were a result of the increases in natural gas and crude oil prices and production levels in 2005 compared to 2004, partially offset by increases in lease operating expenses, exploration expenses and general and administrative expenses. Including the effect of settled derivatives, sales of oil and gas increased $12.4 million in 2005 compared to 2004, with realized crude oil and natural gas prices and production volumes both increasing 13% in 2005 compared to 2004. Operating cash flow amounts are net of changes in our current assets and current liabilities, which resulted in increases to our operating cash flow in the amounts of $13.2 million and $14.1 million, respectively, in the years ended December 31, 2005 and 2004, reflecting increased revenue and expenditure activity associated with our Cotton Valley Trend wells.

*Investing activities*. Net cash used in investing activities was $163.6 million for the year ended December 31, 2005, compared to $45.4 million for the year ended December 31, 2004. For the year ended December 31, 2005, capital expenditures totaled $164.6 million primarily due to development on our Cotton Valley Trend wells, which accounted for 85% of the capital costs incurred in 2005. For the year ended December 31, 2004, capital expenditures totaled $47.5 million, as we incurred substantial drilling and leasehold acquisition costs in East Texas and Northwest Louisiana and participated in the drilling of two successful exploratory wells and one successful sidetrack well in the Burrwood/West Delta 83 field. Offsetting these capital expenditures were sales of non-core properties in West Texas and another minor property in the total amount of $2.1 million.

*Financing activities.* Net cash provided by financing activities was $134.4 million for the year ended December 31, 2005, compared to $6.4 million for the year ended December 31, 2004. In May 2005, we completed a public offering of 3,710,000 shares of our common stock resulting in net proceeds of $53.1 million which was used to repay all then outstanding indebtedness to BNP under a senior credit facility. On

December 21, 2005, we issued and sold 1,650,000 shares of our Series B Convertible Preferred Stock for net proceeds as well as bank borrowings of approximately $79.8 million through a private placement.

Our senior credit facility and term loan include certain financial covenants with which we were in compliance as of December 31, 2006. We do not anticipate a lack of borrowing capacity under our senior credit facility or term loan in the foreseeable future due to an inability to meet any such financial covenants nor a reduction in our borrowing base.

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*3.25% Convertible Senior Notes*

In early December 2006, we issued $125.0 million in convertible senior notes. The intial purchasers option was exercised in full and increased the principal amount to $175.0 million. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes will be our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually and paid semi-annually on June 1 and December 1 beginning June 1, 2007. Prior to December 1, 2011, the notes will not be redeemable. On or after December 11, 2011, we may redeem for cash all or a portion of the notes, and the investors may require us to repay the notes on each of December 11, 2011, 2016 and 2021. The notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus,

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

*Share Lending Agreement*

With the offering of the 3.25% convertible senior notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock. The shares of stock were lent to the affiliate of BSC under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from such common stock offerings and lending transactions under this agreement. We will not receive any of the proceeds from these transactions. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of shares pursuant to the terms of the 3.25% convertible notes offering.

The 3,122,263 shares of common stock outstanding as of December 31, 2006, under the Share Lending Agreement are required to be returned to the Company. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. There is no impact of the shares of common stock lent under the Share Lending Agreement in the earnings per share calculation.

*Senior Credit Facility*

In 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Senior Credit Facility ) and a second lien term loan (the Term Loan ) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Senior Credit Facility were $200.0 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are subject to periodic redeterminations of the borrowing base, which is currently established at $150.0 million, and is scheduled to be redetermined in late March 2007, based upon our 2006 year-end reserve report. With a portion of the net proceeds of the offering of 3.25% Convertible Senior Notes in December 2006, we fully repaid and extinguished the $50.0 million Term Loan and repaid $113.5 million of the Revolving borrowings under the Senior Credit Facility. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at either the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.00%, depending on borrowing base utilization.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms are defined in the credit agreement. The covenants include:

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio which is not less than 3.0/1.0 for the trailing four quarters, and
- Total Debt no greater than 3.5 times EBITDAX (1) for the trailing four quarters.

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(1) EBITDAX is defined as Earnings before interest expense, income tax, DD&A and exploration expense.

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As of December 31, 2006, we were in compliance with all of the financial covenants of the credit agreement.

*Series B Convertible Preferred Stock*

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock ) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears beginning March 15, 2006. If we fail to pay dividends on our Series B Convertible Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum will be increased by 1.0% until we have paid all dividends on our Series B Convertible Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full.

Each share is convertible at the option of the holder into our common stock, par value $0.20 per share (the Common Stock ) at any time at an initial conversion rate of 1.5946 shares of Common Stock per share, which is equivalent to an initial conversion price of approximately $31.36 per share of Common Stock. Upon conversion of the Series B Convertible Preferred Stock, we may choose to deliver the conversion value to holders in cash, shares of Common Stock, or a combination of cash and shares of Common Stock.

If a fundamental change occurs, holders may require us in specified circumstances to repurchase all or part of the Series B Convertible Preferred Stock. In addition, upon the occurrence of a fundamental change or specified corporate events, we will under certain circumstances increase the conversion rate by a number of additional shares of Common Stock. A fundamental change will be deemed to have occurred if any of the following occurs:

We consolidate or merge with or into any person or convey, transfer, sell or otherwise dispose of or lease all or substantially all of our assets to any person, or any person consolidates with or merges into us or with us, in any such event pursuant to a transaction in which our outstanding voting shares are changed into or exchanged for cash, securities, or other property, or

We are liquidated or dissolved or adopt a plan of liquidation or dissolution.

A fundamental change will not be deemed to have occurred if at least 90% of the consideration in the case of a merger or consolidation under the first clause above consists of common stock traded on a U.S. national securities exchange and the Series B Preferred Stock becomes convertible solely into such common stock.

On or after December 21, 2010, we may, at our option, cause the Series B Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock that are issuable at the then-prevailing conversion rate, pursuant to the Company Conversion Option. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days ending on the trading day prior to the announcement of our exercise of the option, the closing price of the Common Stock equals or exceeds 130% of the then-prevailing conversion price of the Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock is non-redeemable by us.

We used the net proceeds of the offering of Series B Convertible Preferred Stock to fully repay all outstanding indebtedness under our senior revolving credit facility. The remaining net proceeds of the offering were added to our working capital to fund 2006 capital expenditures and for other general corporate purposes.

On January 23, 2006, the initial purchasers of the Series B Convertible Preferred Stock exercised their over-allotment option to purchase an additional 600,000 shares at the same price per share, resulting in net proceeds of $29.0 million, which was used to fund our 2006 capital expenditure program.

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**Summary of Critical Accounting Policies**

The following summarizes several of our critical accounting policies. See a complete list in Note 1 Description of Business and Significant Accounting Policies to our consolidated financial statements.

*Proved oil and natural gas reserves*

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 external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by us. We cannot predict the types of reserve revisions that will be required in future periods.

*Successful efforts accounting*

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells, as well as other exploration expenditures such as seismic costs, are expensed and can have a significant effect on operating results. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by engineers. Certain costs related to fields or areas that are not fully developed are charged to expense using the units of production method based on total proved oil and natural gas reserves.

*Impairment of properties*

We continually monitor our long-lived assets recorded in oil and gas properties in the Consolidated Balance Sheets to ensure that 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. Performing these evaluations requires a significant amount of judgment 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 proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. 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 natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. We cannot predict the amount of impairment charges that may be recorded in the future.

*Asset retirement obligations*

We are required to make estimates of the future costs of the retirement obligations of our producing oil and gas properties. This requirement necessitates us to make estimates of our property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

*Income taxes*

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carryforwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements. As of December 31, 2006, and in certain prior years, we have reported a net deferred tax asset on our Consolidated Balance Sheet, after deduction of the related valuation allowance, which has been determined on the basis of management s estimation of the likelihood of realization of the gross deferred tax asset as a deduction against future taxable income.

*Derivative Instruments*

As discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk, we periodically utilize derivative instruments to manage both our commodity price risk and interest rate risk. We consider the use of these instruments to be hedging activities. Pursuant to derivative accounting rules, we are required to use mark to market accounting to reflect the fair value of such derivative instruments on our Consolidated Balance Sheet. To the extent that we are able to demonstrate that our use of derivative instruments qualifies as hedging activities, the offsetting entry to the changes in fair value of these instruments is accounted for in Other Comprehensive Income (Loss). To the extent that such derivatives are deemed to be ineffective, the offsetting entry to the changes in fair value is reflected in earnings.

At the inception of each hedge, we document that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. A hedge must be determined to be highly effective under accounting rules in order to qualify for hedge accounting treatment. This assessment, which is updated quarterly, includes an evaluation of the most recent historical correlation between the derivative and the item hedged. In this analysis, changes in monthly settlement prices on our oil and gas derivatives are compared with the change in physical daily indexed prices that we receive from the field purchasers for our oil and gas production designated for hedging. Should a hedge not be highly effective , it no longer qualifies for hedge accounting treatment and changes in fair value of the hedge are recognized in earnings.

Price volatility within a measured month is the primary factor affecting the analysis of effectiveness of our oil and natural gas swaps. Volatility can reduce the correlation between the hedge settlement price and the price received for physical deliveries. Secondary factors contributing to changes in pricing differentials include changes in the basis differential which is the difference in the locally indexed price received for daily physical deliveries of hedged quantities and the index price used in hedge settlement, and changes in grade and quality factors of the hedged oil and natural gas production which would further impact the price received for physical deliveries.

Not withstanding the determination that certain commodity swaps in 2005 and the fourth quarter of 2006, were not highly effective, management continues to believe that our oil and gas price hedge strategy has been effective in satisfying our financial objective of providing cash flow stability.

Our hedge agreements currently consist of (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. The terms of our current hedge agreements are described in Note 8 Hedging Activities to our consolidated financial statements.

*Share-Based Compensation Plans*

For all new, modified and unvested share-based payment transactions with employees, we measure at fair value and recognize as compensation expense over the requisite period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by

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us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero.

*New Accounting Pronouncements*

See Note 1 Description of Business and Significant Accounting Policies New Accounting Pronouncements to our consolidated financial statements.

*Off-Balance Sheet Arrangements*

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

**Item 7A.** ***Quantitative and Qualitative Disclosures About Market Risk.***

*Commodity Price Risk*

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

We enter into futures contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We consider these agreements to be hedging activities and, as such, monthly settlements on the contracts that qualify for hedge accounting are reflected in our crude oil and natural gas sales. Our strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of December 31, 2006, the commodity hedges we utilized were in the form of: (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. See Note 8 Hedging Activities to our consolidated financial statements for additional information.

Our hedging contracts fall within our targeted range of 30% to 70% of our estimated net oil and gas production volumes for the applicable periods of 2006. The fair value of the crude oil and natural gas hedging contracts in place at December 31, 2006, resulted in an asset of $13.4 million. Based on oil and gas pricing in effect at December 31, 2006, a hypothetical 10% increase in oil and gas prices would have decreased the derivative asset to $11.9 million while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $14.9 million.

*Interest Rate Risk*

We have a variable-rate debt obligation that exposes us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At December 31, 2006, we had the following interest rate swaps in place with BNP (in millions).

| Effective Date | Maturity Date | LIBOR Swap Rate | Notional Amount |
|---|---|---|---|
| 02/27/06 | 02/26/07 | 4.08% | 23.0 |
| 02/27/06 | 02/26/07 | 4.85% | 17.0 |
| 02/27/07 | 02/26/09 | 4.86% | 40.0 |

The fair value of the interest rate swap contracts in place at December 31, 2006, resulted in an asset of $0.2 million. Based on interest rates at December 31, 2006, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the asset.

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### Item 8. *Financial Statements and Supplementary Data*

The information required here is included in the report as set forth in the Index to Consolidated Financial Statements on page 49.

### Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

### Item 9A. *Controls and Procedures*

***Disclosure Controls and Procedures***

*Evaluation of Disclosure Controls and Procedures*

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by SEC rule 13a-15(b), we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of December 31, 2006, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, is set forth on page 50 of this Annual Report on Form 10-K and is incorporated by reference herein.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

*Changes in Internal Control over Financial Reporting*

The following changes in our internal control over financial reporting during our most recent fiscal quarter have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

As previously reported in our quarterly report on Form 10-Q for the quarter ended March 31, 2006, a material weakness was identified in our internal control over financial reporting with respect to recording the fair value of all outstanding derivatives. The Public Company Accounting Oversight Board s Auditing Standard No. 2 defines a material weakness as a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

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In order to remediate the material weakness, we implemented changes in our internal control over financial reporting during the quarters ended June 30, 2006, September 30, 2006, and December 31, 2006. Specifically, we now automatically receive a mark to market valuation from our existing counterparties for all outstanding derivatives. For any new contracts entered into with a new counterparty, we will concurrently request this automatic distribution. We also added another layer of review for the fair value calculation prior to review by the Chief Financial Officer.

Our management believes that these additional policies and procedures have enhanced our internal control over financial reporting relating to the determination and review of fair value calculations on outstanding derivatives. Our management also believes that, as a result of these measures described above, the material weakness was remediated and that our internal control over financial reporting is effective as of December 31, 2006, the end of the period covered in this report.

**Item 9B.** ***Other Information.***

None.

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## PART III

### Item 10. *Directors and Executive Officers of the Registrant and Corporate Governance*

Our executive officers and directors and their ages and positions as of March 9, 2007, are as follows:

| Name | Age | Position |
|---|---|---|
| Patrick E. Malloy, III | 64 | Chairman of the Board of Directors |
| Walter G. Gil Goodrich | 48 | Vice Chairman, Chief Executive Officer and Director |
| Robert C. Turnham, Jr. | 49 | President, Chief Operating Officer and Director |
| David R. Looney | 50 | Executive Vice President and Chief Financial Officer |
| Mark E. Ferchau | 52 | Executive Vice President |
| James B. Davis | 44 | Senior Vice President, Engineering and Operations |
| Henry Goodrich | 76 | Chairman Emeritus and Director |
| Josiah T. Austin | 60 | Director |
| John T. Callaghan | 52 | Director |
| Geraldine A. Ferraro | 71 | Director |
| Michael J. Perdue | 52 | Director |
| Arthur A. Seeligson | 48 | Director |
| Gene Washington | 60 | Director |
| Steven A. Webster | 55 | Director |

Patrick E. Malloy, III became Chairman of the Board of Directors in February 2003. He has been President and Chief Executive Officer of Malloy Enterprises, Inc., a real estate and investment holding company since 1973. In addition, Mr. Malloy served as a director of North Fork Bancorporation, Inc. (NYSE) from 1998 to 2002 and was Chairman of the Board of New York Bancorp, Inc. (NYSE) from 1991 to 1998. He joined the Company s Board in May 2000.

Walter G. Gil Goodrich became Vice Chairman of the Board of Directors in February 2003. He has served as the Company s Chief Executive Officer since August 1995. Mr. Goodrich was Goodrich Oil Company s Vice President of Exploration from 1985 to 1989 and its President from 1989 to August 1995. He joined Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company, as an exploration geologist in 1980. Gil Goodrich is the son of Henry Goodrich. He has served as one of the Company s directors since August 1995.

Robert C. Turnham, Jr. has served as the Company s Chief Operating Officer since August 1995 and became President and Chief Operating Officer in February 2003. Mr. Turnham joined the Board of Directors of the Company in December 2006. He has held various positions in the oil and natural gas business since 1981. From 1981 to 1984, Mr. Turnham served as a financial analyst for Pennzoil. In 1984, he formed Turnham Interests, Inc. to pursue oil and natural gas investment opportunities. From 1993 to August 1995, he was a partner in and served as President of Liberty Production Company, an oil and natural gas exploration and production company.

David R. Looney joined us as Executive Vice President and Chief Financial Officer in May 2006, Mr. Looney has over twenty-five years of experience in the energy finance business, most recently as the Executive Vice President and Chief Financial Officer of Energy Partners, Ltd., a publicly traded E&P company, from March 2005 to April 2006 and Vice President, Finance and Treasurer of EOG Resources, Inc., one of the largest publicly traded E&P Companies in the U.S., from August 1999 to February 2005.

Mark E. Ferchau became Executive Vice President in April 2004. From February 2003 to April 2004, he served as our Senior Vice President, Engineering and Operations, after initially joining us as Vice President in September 2001. Mr. Ferchau previously worked in the divestment group of Forest Oil Corporation, an oil and gas exploration and production company, from December 2000 to September 2001 after the merger with

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Forcenergy Inc. Prior to the merger, he served as Production Manager for Forcenergy Inc., a publicly-held oil and gas exploration and production company, from October 1997 to December 2000. From July 1993 to October 1997, he held various positions including Vice President, Engineering of Convest Energy Corporation and Edisto Resources Corporation, which were publicly-held oil and gas exploration and development companies. From June 1982 to July 1993, Mr. Ferchau held various positions with Wagner & Brown, Ltd., a privately held oil and gas exploration and development company. Prior thereto, he held various positions with various independent oil and gas exploration and development companies and oilfield service companies.

James B. Davis became our Senior Vice President, Engineering and Operations, in January 2005. From February 2003 to December 2004, he served as our Vice President, Engineering and Operations, after initially joining us as Manager of Engineering and Operations in March 2002. Mr. Davis consulted as an independent drilling engineer from May 2001 to March 2002 and served as Senior Staff Drilling Engineer (and acting Drilling Manager during the Forest Oil acquisition) for Forcenergy Inc, responsible for daily drilling activities and engineering for GOM projects, from January 2000 to May 2001. In addition, Mr. Davis worked for Texaco E&P Inc., in various positions in production engineering and rig operations for fields throughout Southeast Louisiana and GOM projects from November 1987 to January 2000.

Henry Goodrich is the Chairman of the Board of Directors Emeritus. Mr. Goodrich began his career as an exploration geologist with the Union Producing Company and McCord Oil Company in the 1950 s. From 1971 to 1975, Mr. Goodrich was President, Chief Executive Officer and a partner of McCord-Goodrich Oil Company. In 1975, Mr. Goodrich formed Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company. He was elected to our board in August 1995, and served as Chairman of the Board from March 1996 through February 2003. Mr. Goodrich is also a director of Pan American Life Insurance Company. Henry Goodrich is the father of Walter G. Goodrich.

Josiah T. Austin is the managing member of El Coronado Holdings, L.L.C., a privately owned investment holding company. He and his family own and operate agricultural properties in the state of Arizona and Sonora, Mexico through El Coronado Ranch & Cattle Company, L.L.C. and other entities. Mr. Austin previously served on the Board of Directors of Monterey Bay Bancorp of Watsonville, California, and is a prior board member of New York Bancorp, Inc., which merged with North Fork Bancorporation, Inc. (NYSE) in early 1998. He was elected to the Board of Directors of North Fork Bancorporation, Inc. in May 2004. He became one of our directors in August 2002.

John T. Callaghan is a partner with the firm of Callaghan Nawrocki LLP, an audit, tax and consulting firm with offices in Melville and Smithtown, New York. He is a Certified Public Accountant and a member of the Association of Certified Fraud Examiners. He was employed by a major accounting firm from 1979 until 1986, at which time he formed his present firm. Mr. Callaghan also serves as a director for Andrea Systems LLC. He was elected to our Board of Directors in June 2003.

Geraldine A. Ferraro is a Principal in the Government Relations Practice of Blank Rome, a national law firm. Prior to joining Blank Rome Government Relations, Ms. Ferraro was head of the Public Affairs Practice of The Global Consulting Group, a New York-based international investor relations and corporate communications firm, where she continues as a Senior Advisor. Ms. Ferraro served as a Member of Congress for three terms prior to accepting the Democratic nomination for vice-president in 1984. She is a Board member of the National Democratic Institute of International Affairs and a member of the Council on Foreign Relations and was formerly United States Ambassador to the United Nations Human Rights Commission. Ms. Ferraro has been affiliated with numerous public and private sector organizations, including serving as a director of the former New York Bancorp, Inc., a NYSE-listed company. She was elected to our Board of Directors in August 2003.

Michael J. Perdue is the President of First Community Bancorp, a publicly traded holding company and of Pacific Western Bank, a subsidiary of the holding company, based in San Diego, California. Prior to assuming his present position in October 2006, Mr. Perdue was President and Chief Executive Officer of Community Bancorp Inc., from July 2003. Prior to Community Bancorp Inc. Mr. Perdue was Executive Vice President of Entrepreneurial Corporate Group and President of its subsidiary, Entrepreneurial Capital Corporation. From

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September 1993 to April 1999, Mr. Perdue served in executive positions with Zions Bancorporation and FP Bancorp, Inc., as a result of FP Bancorp s acquisition by Zions Bancorporation in May 1998. He has also held senior management positions with Ranpac, Inc., a real estate development company, and PacWest Bancorp. He was elected to our Board of Directors in January 2001.

Arthur A. Seeligson is currently engaged in the management of his personal investments in Houston, Texas. From 1991 to 1993, Mr. Seeligson was a Vice President, Energy Corporate Finance, at Schroder Wertheim & Company, Inc. From 1993 to 1995, Mr. Seeligson was a Principal, Corporate Finance, at Wasserstein, Perella & Co. He was primarily engaged in the management of his personal investments from 1995 through 1997. He was a managing director with the investment banking firm of Harris, Webb & Garrison from 1997 to June 2000. He has served as one of our directors since August 1995.

Gene Washington is the Director of Football Operations with the National Football League (NFL) in New York. He previously served as a professional sportscaster and as Assistant Athletic Director for Stanford University prior to assuming his present position with the NFL in 1994. Mr. Washington serves and has served on numerous corporate and civic boards, including serving as a director for Delia s, a NYSE-listed company as well as a director of the former New York Bancorp, Inc., a NYSE-listed company. He was elected to our Board of Directors in June 2003.

Steven A. Webster is Co-Managing Partner of Avista Capital Partners, which makes private equity investments in energy, healthcare and media. From 2000 through June 2005, he was Chairman of Global Energy Partners, an affiliate of the Merchant Banking Division of Credit Suisse First Boston, which made private equity investments in the energy industry. He was Chairman and Chief Executive Officer of Falcon Drilling Company, a marine oil and gas drilling contractor from 1988 to 1997, and was President and Chief Executive Officer of its successor, R&B Falcon Corporation from 1998 to 1999. Mr. Webster is Chairman of the Board of Carrizo Oil & Gas, Inc., a NASDAQ traded oil and gas exploration company and Basic Energy Services, a NYSE traded oil service company. He serves on the board of directors of numerous other public and private companies, primarily in the energy industry. He was elected to our Board of Directors in August 2003.

Additional information required under Item 10, Directors and Executive Officers of the Registrant, and Corporate Governance, will be provided in our Proxy Statement for the 2006 Annual Meeting of Stockholders. Additional information regarding our corporate governance guidelines as well as the complete texts of its Code of Business Conduct and Ethics and the charters of our Audit Committee and our Compensation Committee may be found on our website at *www.goodrichpetroleum.com.*

**Item 11.** ***Executive Compensation*****.**

The information required by this Item is incorporated by reference to the information provided under the caption Executive Compensation and Other Information in our definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**Item 12.** ***Security Ownership of Certain Beneficial Owners and Management*****.**

The information required by this Item is incorporated by reference to the information provided under the caption Security Ownership of Certain Beneficial Owners and Management in our definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**Item 13.** ***Certain Relationships and Related Transactions, and Director Independence*.**

The information required by this Item is incorporated by reference to the information provided under the caption Certain Relationships and Other Transactions in our definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

**Item 14.** ***Principal Accounting Fees and Services*.**

The information required by this Item is incorporated by reference to the information provided under the caption Audit and Non-Audit Fees in our definitive proxy statement for the 2007 annual meeting of stockholders to be filed within 120 days from December 31, 2006.

## PART IV

**Item 15.** ***Exhibits and Financial Statement Schedules***

**(a) (1) and (2) Financial Statements and Financial Statement Schedules**

See Index to Consolidated Financial Statements on page 48.

**(a) (3) Exhibits**

| | |
|---|---|
| 1.1 | Purchase Agreement by among Goodrich Petroleum Corporation, Bear, Sterns & Co. Inc. and BNP Paribas Securities Corp. and dated December 16, 2005 (Incorporated by reference to Exhibit 1.1 of the Company s Form 8-K filed on December 16, 2005). |
| 3.1 | Amended and Restated Certificate of Incorporation of Goodrich Petroleum Corporation dated March 12, 1998 (Incorporated by reference to Exhibit 3.1 of the Company s First Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed November 22, 2000). |
| 3.2 | Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.3 of the Company s First Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed November 22, 2000). |
| 3.3 | Certificate of Designation of 5.375% Series B Cumulative Convertible Preferred Stock (Incorporated by reference to Exhibit 1.1 of the Company s Form 8-K filed on December 22, 2005). |
| 4.1 | Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.6 of the Company s Registration Statement filed February 20, 1996 on Form S-8 (File No. 33-01077)). |
| 4.2 | Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated November 9, 2001 (Incorporated by reference to Exhibit 4.2 of the Company s Annual Report on Form 10-K for the year ended December 31, 2001). |
| 4.3 | Registration Rights Agreement dated December 21, 2005 among the Company, Bear, Sterns & Co. Inc. and BNP Paribas Securities Corp. (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 22, 2005). |
| 4.4 | Goodrich Petroleum Corporation 2006 Long-Term Incentive Plan (Incorporated by reference to the Company s Proxy Statement filed April 17, 2006). |
| 4.5 | Form of Grant of Restricted Phantom Stock (1995 Stock Option Plan) (Incorporated by reference to Exhibit 4.2 to the Company s Registration Statement on Form S-8 filed on October 23, 2006) |
| 4.6 | Form of Grant of Restricted Phantom Stock (2006 Long-Term Incentive Plan) (Incorporated by reference to Exhibit 4.3 to the Company s Registration Statement on Form S-8 filed on October 23, 2006). |
| 4.7 | Form of Director Stock Option Agreement (with vesting schedule) (Incorporated by reference to Exhibit 4.4 to the Company s Registration Statement on Form S-8 filed on October 23, 2006). |
| 4.8 | Form of Director Stock Option Agreement (immediate vesting) (Incorporated by reference to Exhibit 4.5 to the Company s Registration Statement on Form S-8 filed on October 23, 2006). |
| 4.9 | Form of Incentive Stock Option Agreement (Incorporated by reference to Exhibit 4.6 to the Company s Registration Statement on Form S-8 filed on October 23, 2006). |
| 4.10 | Form of Nonqualified Option Agreement (Incorporated by reference to Exhibit 4.7 to the Company s Registration Statement on Form S-8 filed on October 23, 2006). |

| | |
|---|---|
| *4.11 | Registration Rights Agreement dated December 6, 2006 among Goodrich Petroleum Corporation, Bear, Sterns & Co. Inc., Deutsche Bank Securities Corp. and BNP Paribus Securities Corp. |
| *4.12 | Indenture, dated December 6, 2006, between Goodrich Petroleum Corporation and Wells Fargo Bank, National Association, as Trustee. |
| 10.1 | Goodrich Petroleum Corporation 1995 Stock Option Plan (Incorporated by reference to Exhibit 10.21 to the Company s Registration Statement filed June 13, 1995 on Form S-4 (File No. 33-58631)). |
| 10.2 | Consulting Services Agreement between Patrick E. Malloy and Goodrich Petroleum Corporation dated June 1, 2001 (Incorporated by reference to Exhibit 10.3 of the Company s Annual Report filed on Form 10-K for the year ended December 31, 2001). |

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| | |
|---|---|
| 10.3 | Goodrich Petroleum Corporation 1997 Non-Employee Director Compensation Plan (Incorporated by reference to the Company s Proxy Statement filed April 27, 1998). |
| 10.4 | Form of Subscription Agreement dated September 27, 1999 (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K dated October 15, 1999). |
| 10.5 | Purchase and Sale Agreement between Goodrich Petroleum Company, LLC and Malloy Energy Company, LLC, dated March 4, 2002 (Incorporated by reference to Exhibit 10.7 of the Company s Annual Report on Form 10-K for the year ended December 31, 2002). |
| 10.6 | Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated February 25, 2005 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on April 21, 2005). |
| 10.7 | Severance Agreement between the Company and Walter G. Goodrich, dated April 25, 2003 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on April 21, 2005) |
| 10.8 | Severance Agreement between the Company and Robert C. Turnham, Jr., dated April 25, 2003 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on April 21, 2005) |
| 10.9 | First Amendment to the Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated April 29, 2005 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report Form 10-Q for the quarterly period ended March 31, 2005). |
| 10.10 | Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated November 17, 2005 (Incorporated by reference to Exhibit 4.2 of the Company s Form 8-K filed on November 23, 2005). |
| 10.11 | Second Lien Term Loan Agreement among Goodrich Petroleum Company L.L.C., BNP Paribas and Certain Lenders, dated as of November 17, 2005 (Incorporated by reference to Exhibit 4.3 of the Company s Form 8-K filed on November 23, 2005). |
| 10.12 | First Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas dated as of December 14, 2005 (Incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on December 20, 2005). |
| 10.13 | First Amendment to Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C., BNP Paribas and Certain Lenders, dated as of December 14, 2005 (Incorporated by reference to Exhibit 4.2 of the Company s Form 8-K filed on December 20, 2005). |
| 10.14 | Letter Agreement by and between D. Hughes Walter, Jr. and Goodrich Petroleum Corporation dated May 8, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on May 10, 2006). |
| 10.15 | Second Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas, dated as of June 21, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2006). |
| 10.16 | Second Amendment to Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of June 21, 2006 (Incorporated by reference to Exhibit 10.2 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2006). |
| 10.17 | Third Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of August 30, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 6, 2006). |
| 10.18 | Third Amendment to Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of August 30, 2006 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on September 6, 2006). |
| 10.19 | Share Lending Agreement, dated November 30, 2006, among Goodrich Petroleum Corporation, Bear, Stearns & Co. Inc. and Bear Stearns International Limited (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on December 4, 2006). |

| | |
|---|---|
| 10.20 | Forth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of November 30, 2006 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on December 4, 2006). |
| 10.21 | Severance Agreement with James Davis dated December 12, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 8, 2007). |
| 10.22 | Severance Agreement with David R. Looney dated May 8, 2006 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 10, 2007). |
| 10.23 | Severance Agreement wit Mark E. Ferchau dated April 1, 2005 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on January 10, 2007). |
| 10.24 | Purchase and Sale Agreement, dated January 12, 2007, among Goodrich Petroleum Corporation, Malloy Energy Company, LLC and Hilcorp Energy I, L.P. (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 19, 2007). |
| 10.25 | Goodrich Petroleum Corporation Annual Bonus Plan. |
| *12.1 | Ratio of Earnings to Fixed Charges |
| *12.2 | Ratio of Earnings to Fixed Charges and Preference Securities Dividends |
| 21 | Subsidiaries of the Registrant |
| | Goodrich Petroleum Company LLC organized in state of Louisiana |
| | Goodrich Petroleum Company Lafitte, LLC organized in state of Louisiana |
| | Drilling & Work over Company, Inc. incorporated in state of Louisiana |
| | LECE, Inc. incorporated in the state of Texas |
| *23.1 | Consent of KPMG LLP Independent Registered Public Accounting Firm |
| *23.2 | Consent of Netherland, Sewell & Associates, Inc. |
| *24.1 | Power of Attorney (included on signature page hereto). |
| *31.1 | Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *31.2 | Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *32.1 | Certification by Chief Executive Officer 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 Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

* Filed herewith.
Denotes management contract or compensatory plan or arrangement.

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**GLOSSARY OF CERTAIN OIL AND GAS TERMS**

As used herein, the following terms have specific meanings as set forth below:

| | |
|---|---|
| *MBbls* | Barrels of crude oil or other liquid hydrocarbons |
| *Bcf* | Billion cubic feet |
| *Bcfe* | Billion cubic feet equivalent |
| *MBbls* | Thousand barrels of crude oil or other liquid hydrocarbons |
| *Mcf* | Thousand cubic feet of natural gas |
| *Mcfe* | Thousand cubic feet equivalent |
| *MMBbls* | Million barrels of crude oil or other liquid hydrocarbons |
| *MMBtu* | Million British thermal units |
| *MMcf* | Million cubic feet of natural gas |
| *MMcfe* | Million cubic feet equivalent |
| *MMBoe* | Million barrels of crude oil or other liquid hydrocarbons equivalent |
| *SEC* | United States Securities and Exchange Commission |
| *U.S.* | United States |

Crude oil and other liquid hydrocarbons are converted into cubic feet of gas equivalent based on six Mcf of gas to one barrel of crude oil or other liquid hydrocarbons.

*Development well* is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

*Dry hole* is a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

*Farm-in or farm-out* is an agreement whereby the owner of a working interest in an oil and gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor (the farmor ) usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

*Field* is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

*PV10* is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions).

*Productive well* is a well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

*Proved reserves* are the estimated quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, can be recovered in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests.

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*Proved developed reserves* are the portion of proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

*Proved undeveloped reserves* are the portion of 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.

*Working interest* is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

*Workover* is a series of operations on a producing well to restore or increase production.

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## 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.

GOODRICH PETROLEUM CORPORATION

By: /s/ WALTER G. GOODRICH

**Walter G. Goodrich**

**Chief Executive Officer**

## POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Walter G. Goodrich and David R. Looney and each of them, his true and lawful attorney-in-fact and agent, with full powers of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting to said attorneys-in-fact, and each of them, full power and authority to perform any other act on behalf of the undersigned required to be done in connection therewith.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant in the capacities indicated on March 13, 2007.

| Signature | Title |
|---|---|
| /s/ WALTER G. GOODRICH<br>**Walter G. Goodrich** | Vice Chairman, Chief Executive Officer and Director (Principal Executive Officer) |
| /s/ DAVID R. LOONEY<br>**David R. Looney** | Executive Vice President and Chief Financial Officer (Principal Financial Officer) |
| /s/ JAN L. SCHOTT<br>**Jan L. Schott** | Vice President and Controller (Principal Accounting Officer) |
| /s/ PATRICK E. MALLOY, III<br>**Patrick E. Malloy, III** | Chairman of Board of Directors |
| /s/ ROBERT C. TURNHAM, JR. | President, Chief Operating Officer and Director |

| | |
|---|---|
| **Robert C. Turnham, Jr.** | |
| /s/ JOSIAH T. AUSTIN | Director |
| **Josiah T. Austin** | |
| /s/ JOHN T. CALLAGHAN | Director |
| **John T. Callaghan** | |
| /s/ GERALDINE A. FERRARO | Director |
| **Geraldine A. Ferraro** | |
| /s/ HENRY GOODRICH | Director |
| **Henry Goodrich** | |

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| Signature | Title |
|---|---|
| /s/ MICHAEL J. PERDUE<br>**Michael J. Perdue** | Director |
| /s/ ARTHUR A. SEELIGSON<br>**Arthur A. Seeligson** | Director |
| /s/ GENE WASHINGTON<br>**Gene Washington** | Director |
| /s/ STEVEN A. WEBSTER<br>**Steven A. Webster** | Director |

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**INDEX TO CONSOLIDATED FINANCIAL STATEMENTS**

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**MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROLS**

**OVER FINANCIAL REPORTING**

Management is responsible for establishing and maintaining effective 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 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. Our 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 board of 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. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in Internal Control Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2006. Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included on page 52.

Management of Goodrich Petroleum Corporation

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## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Goodrich Petroleum Corporation:

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

We conducted our audits in accordance with 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 financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share based payments.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 14, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

New Orleans, Louisiana

March 14, 2007

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**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders

Goodrich Petroleum Corporation:

We have audited management s assessment, included in the accompanying report, Management s Annual Report on Internal Controls over Financial Reporting , that Goodrich Petroleum Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Goodrich Petroleum Corporation 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 Goodrich Petroleum Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Goodrich Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Goodrich Petroleum Corporation and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, cash flows, stockholders equity, and comprehensive income (loss), for each of the years in the three-year period ended December 31, 2006, and our report dated March 14, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

New Orleans, Louisiana

March 14, 2007

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEETS**

***(In Thousands, Except Share Amounts)***

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 6,184 | $ 19,842 |
| Accounts receivable, trade and other, net of allowance | 9,665 | 6,397 |
| Accrued oil and gas revenue | 10,689 | 11,863 |
| Fair value of oil and gas derivatives | 13,419 | |
| Fair value of interest rate derivatives | 219 | 107 |
| Prepaid expenses and other | 994 | 463 |
| Total current assets | 41,170 | 38,672 |
| PROPERTY AND EQUIPMENT: | | |
| Oil and gas properties (successful efforts method) | 575,666 | 316,286 |
| Furniture, fixtures and equipment | 1,463 | 1,075 |
| | 577,129 | 317,361 |
| Less: Accumulated depletion, depreciation and amortization | (156,509) | (74,229) |
| Net property and equipment | 420,620 | 243,132 |
| OTHER ASSETS: | | |
| Restricted cash and investments | 2,039 | 2,039 |
| Deferred tax asset | 9,705 | 11,580 |
| Other | 5,730 | 1,103 |
| Total other assets | 17,474 | 14,722 |
| TOTAL ASSETS | $ 479,264 | $ 296,526 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 36,263 | $ 31,574 |
| Accrued liabilities | 26,811 | 15,973 |
| Fair value of oil and gas derivatives | | 23,271 |
| Accrued abandonment costs | 263 | 92 |
| Total current liabilities | 63,337 | 70,910 |
| LONG-TERM DEBT | 201,500 | 30,000 |
| Accrued abandonment costs | 9,294 | 7,868 |
| Fair value of oil and gas derivatives | | 6,159 |

| | | |
|---|---|---|
| Total liabilities | 274,131 | 114,937 |
| Commitments and contingencies (See Note 10) | | |
| STOCKHOLDERS EQUITY: | | |
| Preferred stock: 10,000,000 shares authorized: | | |
| Series A convertible preferred stock, $1.00 par value, issued and outstanding none and 791,968 shares, respectively | | 792 |
| Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 and 1,650,000 shares, respectively | 2,250 | 1,650 |
| Common stock: $0.20 par value, 50,000,000 shares authorized; issued and outstanding 28,218,422 and 24,804,737 shares, respectively | 5,049 | 4,961 |
| Additional paid in capital | 213,666 | 187,967 |
| Accumulated deficit | (14,571) | (8,649) |
| Unamortized restricted stock awards | | (2,066) |
| Accumulated other comprehensive loss | (1,261) | (3,066) |
| Total stockholders equity | 205,133 | 181,589 |
| TOTAL LIABILITIES AND STOCKHOLDERS EQUITY | $ 479,264 | $ 296,526 |

See accompanying notes to consolidated financial statements.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

***(In Thousands, Except Per Share Amounts)***

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| REVENUES: | | | |
| Oil and gas revenues | $ 113,696 | $ 68,387 | $ 44,861 |
| Other | 2,458 | 1,016 | 151 |
| | 116,154 | 69,403 | 45,012 |
| OPERATING EXPENSES: | | | |
| Lease operating expense | 21,877 | 9,931 | 7,402 |
| Production taxes | 5,993 | 4,053 | 3,105 |
| Transportation | 4,013 | 558 | |
| Depreciation, depletion and amortization | 52,642 | 25,563 | 11,562 |
| Exploration | 15,058 | 6,867 | 4,426 |
| Impairment of oil and gas properties | 24,790 | 340 | |
| General and administrative | 17,223 | 8,622 | 5,821 |
| (Gain) loss on sale of assets | (23) | (235) | (50) |
| Other | 1,709 | 512 | |
| | 143,282 | 56,211 | 32,266 |
| Operating income (loss) | (27,128) | 13,192 | 12,746 |
| OTHER INCOME (EXPENSE): | | | |
| Interest expense | (7,845) | (2,359) | (1,110) |
| Gain (loss) on derivatives not qualifying for hedge accounting | 38,128 | (37,680) | 2,317 |
| Loss on early extinguishment of debt | (612) | | |
| Gain on litigation judgment | | | 2,118 |
| | 29,671 | (40,039) | 3,325 |
| INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES | 2,543 | (26,847) | 16,071 |
| INCOME TAX (EXPENSE) BENEFIT | (904) | 9,397 | 1,707 |
| INCOME (LOSS) FROM CONTINUING OPERATIONS | 1,639 | (17,450) | 17,778 |
| Discontinued operations including gain on sale of assets, net of tax | | | 749 |
| NET INCOME (LOSS) | 1,639 | (17,450) | 18,527 |
| PREFERRED STOCK DIVIDENDS | 6,016 | 755 | 633 |
| PREFERRED STOCK REDEMPTION PREMIUM | 1,545 | | |

| | | | |
|---|---|---|---|
| NET INCOME (LOSS) APPLICABLE TO COMMON STOCK | $ (5,922) | $ (18,205) | $ 17,894 |
| NET INCOME (LOSS) PER COMMON SHARE BASIC | | | |
| INCOME (LOSS) FROM CONTINUING OPERATIONS | $ 0.07 | $ (0.75) | $ 0.91 |
| DISCONTINUED OPERATIONS | | | 0.04 |
| NET INCOME (LOSS) | $ 0.07 | $ (0.75) | $ 0.95 |
| NET INCOME (LOSS) APPLICABLE TO COMMON STOCK | $ (0.24) | $ (0.78) | $ 0.92 |
| NET INCOME (LOSS) PER COMMON SHARE DILUTED | | | |
| INCOME (LOSS) FROM CONTINUING OPERATIONS | $ 0.06 | $ (0.75) | $ 0.87 |
| DISCONTINUED OPERATIONS | $ | $ | 0.04 |
| NET INCOME (LOSS) | $ 0.06 | $ (0.75) | $ 0.91 |
| NET INCOME (LOSS) APPLICABLE TO COMMON STOCK | $ (0.24) | $ (0.78) | $ 0.88 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING BASIC | 24,948 | 23,333 | 19,552 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING DILUTED | 25,412 | 23,333 | 20,347 |

See accompanying notes to consolidated financial statements.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

***(In Thousands)***

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net Income (loss) | $ 1,639 | $ (17,450) | $ 18,527 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | |
| Depletion, depreciation, and amortization | 52,642 | 25,563 | 11,562 |
| Unrealized (gain) loss on derivatives not qualifying for hedge accounting | (40,185) | 26,960 | (2,317) |
| Deferred income taxes | 904 | (9,396) | (1,303) |
| Dry hole costs | 7,926 | 2,014 | |
| Amortization of leasehold costs | 5,488 | 3,344 | 1,035 |
| Impairment of oil and gas properties | 24,790 | 340 | |
| Stock based compensation (non-cash) | 5,962 | 1,383 | 1,031 |
| Loss on early extinguishment of debt | 612 | | |
| Gain on sale of assets | (23) | (235) | (814) |
| Non-cash effect of discontinued operations, net | | | 155 |
| Other non-cash items | 476 | (156) | (967) |
| Change in assets and liabilities: | | | |
| Accounts receivable, trade and other, net of allowance | (3,268) | 786 | (3,683) |
| Accrued oil and gas revenue | 1,174 | (8,741) | (293) |
| Prepaid expenses and other | (531) | 169 | (280) |
| Accounts payable | 4,689 | 8,222 | 16,644 |
| Accrued liabilities | 2,838 | 12,759 | 1,731 |
| Net cash provided by operating activities | 65,133 | 45,562 | 41,028 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Capital expenditures | (261,435) | (164,551) | (47,501) |
| Proceeds from sale of assets | 2,698 | 980 | 2,087 |
| Net cash used in investing activities | (258,737) | (163,571) | (45,414) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Principal payments of bank borrowings | (184,500) | (118,500) | (1,000) |
| Proceeds from bank borrowings | 181,000 | 121,500 | 8,000 |
| Proceeds from convertible note offering | 175,000 | | |
| Net proceeds from common stock offering | | 53,112 | |
| Net proceeds from preferred stock offering | 28,973 | 79,775 | |
| Redemption of preferred stock | (9,319) | | |
| Exercise of stock options and warrants | 406 | 477 | 340 |
| Production payments | | (297) | (361) |
| Deferred financing costs | (5,598) | (971) | |
| Preferred stock dividends | (6,016) | (634) | (633) |
| Other | | (60) | |

| | | | |
|---|---|---|---|
| Net cash provided by financing activities | 179,946 | 134,402 | 6,346 |
| INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (13,658) | 16,393 | 1,960 |
| CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD | 19,842 | 3,449 | 1,489 |
| CASH AND CASH EQUIVALENTS, END OF PERIOD | $ 6,184 | $ 19,842 | $ 3,449 |
| SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION | | | |
| CASH PAID DURING THE YEAR FOR INTEREST | $ 7,284 | $ 1,862 | $ 865 |
| CASH PAID DURING THE YEAR FOR INCOME TAXES | $ | $ 110 | $ 30 |

See accompanying notes to consolidated financial statements.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY**

***(In Thousands)***

| | 2006 | | 2005 | | 2004 | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| **Series A Preferred Stock** | | | | | | |
| Balance, beginning of year | 792 | $ 792 | 792 | $ 792 | 792 | $ 792 |
| Offering of preferred stock | (792) | (792) | | | | |
| Balance, end of year | | $ | 792 | $ 792 | 792 | $ 792 |
| **Series B Preferred Stock** | | | | | | |
| Balance, beginning of year | 1,650 | $ 1,650 | | $ | | $ |
| Offering of preferred stock | | | 1,650 | 1,650 | | |
| Issuance of preferred stock | 600 | 600 | | | | |
| Balance, end of year | 2,250 | $ 2,250 | 1,650 | $ 1,650 | | $ |
| **Common Stock** | | | | | | |
| Balance, beginning of year | 24,805 | $ 4,961 | 20,587 | $ 4,117 | 18,130 | $ 3,626 |
| Offering of common stock | | | 3,710 | 742 | | |
| Redemption of Series A preferred stock | 6 | 1 | | | | |
| Issuance and amortization of restricted stock | 182 | 36 | 123 | 25 | 52 | 10 |
| Exercise of stock options and warrants | 66 | 44 | 371 | 74 | 2,376 | 475 |
| Director stock grants | 37 | 7 | 14 | 3 | 29 | 6 |
| Shares pursuant to share lending agreement | 3,122 | | | | | |
| Balance, end of year | 28,218 | $ 5,049 | 24,805 | $ 4,961 | 20,587 | $ 4,117 |
| **Paid-in Capital** | | | | | | |
| Balance, beginning of year | | $ 187,967 | | $ 55,409 | | $ 53,359 |
| Offering of common stock | | | | 52,370 | | |
| Offering of preferred stock | | 28,373 | | 78,125 | | |
| Redemption of Series A preferred stock | | (6,983) | | | | |
| Issuance and amortization of restricted stock | | 2,205 | | 1,423 | | 1,951 |
| Reclassification from unamortized restricted stock awards upon adoption of FAS 123R | | (2,066) | | | | |
| Stock based compensation | | 2,487 | | | | |
| Exercise of stock options and warrants | | 295 | | 403 | | (135) |
| Director stock grants | | 1,388 | | 237 | | 234 |
| Balance, end of year | | $ 213,666 | | $ 187,967 | | $ 55,409 |
| **Retained Earnings (Deficit)** | | | | | | |
| Balance, beginning of year | | $ (8,649) | | $ 9,556 | | $ (8,338) |
| Net income (loss) | | 1,639 | | (17,450) | | 18,527 |
| Redemption of Series A preferred stock | | (1,545) | | | | |

| | | | |
|---|---|---|---|
| Preferred stock dividends | (6,016) | (755) | (633) |
| Balance, end of year | $ (14,571) | $ (8,649) | $ 9,556 |
| **Unamortized Restricted Stock Awards** | | | |
| Balance, beginning of year | $ (2,066) | $ (1,762) | $ (382) |
| Issuance and amortization of restricted stock | | (304) | (1,380) |
| Reclassification to APIC upon adoption of FAS 123R | 2,066 | | |
| Balance, end of year | $ | $ (2,066) | $ (1,762) |
| **Accumulated Other Comprehensive Loss** | | | |
| Balance, beginning of year | $ (3,066) | $ (2,805) | $ (998) |
| Other comprehensive loss | 1,805 | (261) | (1,807) |
| Balance, end of year | $ (1,261) | $ (3,066) | $ (2,805) |
| **Total Stockholders Equity** | $ 205,133 | $ 181,589 | $ 65,307 |

See accompanying notes to consolidated financial statements.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**

***(In Thousands)***

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Net income (loss) | $ 1,639 | $ (17,450) | $ 18,527 |
| Other comprehensive income (loss): | | | |
| Change in fair value of derivatives (1) | (1,025) | (6,233) | (5,909) |
| Reclassification adjustment (2) | 2,830 | 5,972 | 4,102 |
| Other comprehensive income (loss) | 1,805 | (261) | (1,807) |
| Comprehensive income (loss) | $ 3,444 | $ (17,711) | $ 16,720 |

| | | | |
|---|---|---|---|
| (1) Net of income tax benefit of: | $ 552 | $ 3,356 | $ 3,180 |
| (2) Net of income tax expense of: | $ 1,524 | $ 3,216 | $ 2,209 |

See accompanying notes to consolidated financial statements.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**

**NOTE 1 Description of Business and Significant Accounting Policies**

We are in the primary business of exploration and production of crude oil and natural gas. We and our subsidiaries have interests in such operations in three states, primarily in Texas and Louisiana.

*Principles of Consolidation* The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiaries. Significant intercompany balances and transactions have been eliminated in consolidation. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

*Use of Estimates* Our Management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

*Cash and Cash Equivalents* Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase. Restricted cash represents amounts held in escrow for plugging and abandonment obligations which were incurred with the acquisition of our Burrwood and West Delta 83 fields in 2000.

*Revenue Recognition* Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized on the entitlements method. We record an asset or liability for natural gas balancing when we have purchased or sold more than our working interest share of natural gas production, respectively. At December 31, 2006 and 2005, the net assets for gas balancing were $1.5 million and $0.7 million, respectively. Differences between actual production and net working interest volumes are routinely adjusted. These differences are not significant.

*Property and Equipment* We use the successful efforts method of accounting for exploration and development expenditures. Leasehold acquisition costs are capitalized. When proved reserves are found on an undeveloped property, leasehold cost is reclassified to proved properties. Significant undeveloped leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Cost of all other undeveloped leases is amortized over the estimated average holding period of the leases.

Costs of exploratory drilling are initially capitalized, but if proved reserves are not found the costs are subsequently expensed. All other exploratory costs are charged to expense as incurred. Development costs are capitalized, including the cost of unsuccessful development wells.

We recognize an impairment when the net of future cash inflows expected to be generated by an identifiable long-lived asset and cash outflows expected to be required to obtain those cash inflows is less than the carrying value of the asset. We perform this comparison for our oil and gas properties on a field-by-field basis using our estimates of future commodity prices and proved and probable reserves. The amount of such loss is measured based on the difference between the discounted value of such net future cash flows and the carrying value of the asset. For the years ended December 31, 2006 and 2005, we recorded impairments of $24.8 million and $0.3 million, respectively, as a result of certain non-core fields depleting earlier than anticipated. There were no impairments in 2004.

Depreciation and depletion of producing oil and gas properties are provided under the unit-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs. As described in Note 3, we follow the provisions of Statement of Financial Accounting Standards ( SFAS ) No. 143, *Accounting for Asset*

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Retirement Obligations* ( SFAS 143 ). Our asset retirement obligations are amortized based upon units of production of proved reserves attributable to the properties to which the obligations relate. Some of these obligations relate to an individual producing well or group of producing wells and are amortized based on proved developed reserves attributable to that well or group of wells. Other asset retirement obligations may relate to an entire field or area that is not fully developed. Because these obligations relate to assets installed to service future development, they are amortized based on all proved reserves attributable to the field or area.

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in income. All other dispositions, retirements, or abandonments are reflected in accumulated depreciation, depletion, and amortization.

Furniture, fixtures and equipment consists of office furniture, computer hardware and software and leasehold improvements. Depreciation of these assets is computed using the straight-line method over their estimated useful lives, which vary from one to five years.

*Income Taxes* We follow the provisions of SFAS No. 109, *Accounting for Income Taxes* , ( SFAS 109 ) which requires income taxes be accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

*Earnings Per Share* Basic income per common share is computed by dividing net income available for common stockholders, for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income available for common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive common shares.

*Derivative Instruments and Hedging Activities* We utilize derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ( SFAS 133 ), as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. Upon entering into a derivative contract, we may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, mark the contract to market through earnings. We document the relationship between the derivative instrument designated as a hedge and the hedged items, as well as our objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. We assess at inception, and on an ongoing basis, whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income, until earnings are affected by the cash flows of the hedged item. When the cash flow of the hedged item is recognized in the Statement of Operations, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings.

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Ineffective portions of a cash flow hedging derivative s change in fair value are recognized currently in earnings as other income (expense). If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in other comprehensive income is recognized over the period anticipated in the original hedge transaction.

*Asset Retirement Obligations* We follow SFAS 143 (see Note 3) which applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. SFAS 143 requires that we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

*Commitments and Contingencies* Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, which are probable of realization, are separately recorded, and are not offset against the related environmental liability.

*Concentration of Credit Risk* Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from two purchasers accounted for 35% and 15% of oil and gas revenues for the year ended December 31, 2006. For the year ended December 31, 2005, revenue from three purchasers accounted for 34%, 18% and 13% of oil and gas revenues. For the year ended December 31, 2004, revenues from two purchasers accounted for 45% and 15%, of oil and gas.

*Share-Based Compensation Plans.* In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment* ( SFAS 123R ), replacing SFAS No. 123, *Accounting for Stock-Based Compensation* ( SFAS 123 ), and superseding Accounting Principles Board ( APB ) Opinion No. 25, *Accounting for Stock Issued to Employees* ( APB 25 ). In January 2006, we adopted SFAS 123R which replaces SFAS 123 and supersedes APB 25. SFAS 123R requires new, modified and unvested share-based payment transactions with employees to be measured at fair value and recognized as compensation expense over the requisite service period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero. See Note 2.

*New Accounting Pronouncements* In February 2007, the Financial Accounting Standards Board ( FASB ) issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115,* which allows measurement at fair value of eligible financial assets and liabilities that are not otherwise measured at fair value. If the fair value option for an eligible item is elected, unrealized gains and losses for that item shall be reported in current earnings at each subsequent reporting date. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. Early adoption is permitted. We are currently assessing the impact of SFAS 159 on our financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 ( SAB 108 ), which became effective for fiscal years ending after November 15, 2006. SAB 108 provides

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

guidance on the consideration of the effects of prior period misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 requires an entity to evaluate the impact of correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, on current year financial statements. If a misstatement is material to the current year financial statements, the prior year financial statements should also be corrected, even though such revision was, and continues to be, immaterial to the prior year financial statements. Correcting prior year financial statements for immaterial errors would not require previously filed reports to be amended. Such correction should be made in the current period filings. The adoption of this standard at December 31, 2006 had no impact on the company s financial statements.

In December 2006, FASB issued a FASB Staff Position ( FSP ) EITF 00-19-2 *Accounting for Registration Payment Arrangements* ( FSP 00-19-2 ). This FSP addresses an issuer s accounting for registration payment arrangements. This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with FASB Statement No. 5 *Accounting for Contingencies.* The guidance in this FSP amends FASB Statements No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,* as well as FASB Interpretation No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* to include scope exceptions for registration payment arrangements. This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to the date of issuance of this FSP. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to the issuance of this FSP, this is effective for financial statements issued for fiscal years beginning after December 15, 2006, and interim periods within those fiscal years. We are currently evaluating the impact that the implementation of FSP EITF 00-19-2 may have in our consolidated results of operations and financial position.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ( SFAS 157 ), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements. SFAS 157 is effective for fiscal years beginning after December 15, 2007. We plan to adopt SFAS 157 beginning in the first quarter of fiscal 2008. We are currently evaluating the impact, if any, the adoption of SFAS 157 will have on our consolidated financial position, results of operations or cash flows.

In July 2006, the FASB issued Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* ( FIN 48 ). FIN 48, which clarifies SFAS 109, establishes the criterion that an individual tax position has to meet for some or all of the benefits of that position to be recognized in our consolidated financial statements. On initial application, FIN 48 will be applied to all tax positions for which the statute of limitations remains open. Only tax positions that meet the more-likely-than-not recognition threshold at the adoption date will be recognized or continue to be recognized. The cumulative effect of applying FIN 48 will be reported as an adjustment to retained earnings at the beginning of the period in which it is adopted. FIN 48 is effective for fiscal years beginning after December 15, 2006, and we plan to adopt FIN 48 on January 1, 2007. We do not expect that the adoption of FIN 48 will have a significant effect on our consolidated financial statements or our ability to comply with our current debt covenants.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2006, the FASB issued SFAS No. 156, *Accounting for Servicing of Financial Assets* ( SFAS 156 ), which requires all separately recognized servicing assets and servicing liabilities be initially measured at fair value. SFAS 156 permits, but does not require, the subsequent measurement of servicing assets and servicing liabilities at fair value. Adoption is required as of the beginning of the first fiscal year that begins after September 15, 2006. The adoption of SFAS 156 is not expected to have a material effect on our consolidated financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140* ( SFAS 155 ). SFAS 155 clarifies certain issues relating to embedded derivatives and beneficial interests in securitized financial assets. The provisions of SFAS 155 are effective for all financial instruments acquired or issued after fiscal years beginning after September 15, 2006. We are currently assessing the impact that the adoption of SFAS 155 will have on our consolidated financial position, results of operations or cash flows.

We do not believe that any other recently issued, but not yet effective accounting pronouncements, if adopted, would have a material effect on our accompanying financial statements.

**NOTE 2 Stock-Based Compensation**

***Share-Based Employee Compensation Plans***

*Stock Option and Incentive Programs*

We have historically had two plans, which provide for stock option and other incentive awards for our key employees, consultants and directors: (a) the Goodrich Petroleum Corporation 1995 Stock Option Plan (the 1995 Plan ), which allowed grants of stock options, restricted stock awards, stock appreciation rights, long-term incentive awards and phantom stock awards, or any combination thereof, to key employees and consultants, and (b) the Goodrich Petroleum Corporation 1997 Director Compensation Plan (the Directors Plan ), which allowed grants of stock and options to each director who is not and has never been an employee of the Company. The Goodrich Petroleum Corporation 1995 Stock Option Plan expired according to its original terms in late 2005; however, our Board of Directors approved the extension of the 1995 Plan through December 31, 2005 and the granting of a total of 525,000 stock options at an exercise price of $23.39 and 101,129 shares of restricted stock to certain of our employees and officers as of December 6, 2005, subject to approval at our 2006 Annual Meeting of Stockholders. As of February 9, 2006, our directors and executive officers reached a level of more than 50% ownership of our total shares of Common Stock outstanding; therefore, stockholder approval of these actions was no longer contingent. For accounting purposes, we began expensing the December 6, 2005 grants based on the grant date value as determined under SFAS 123R, which utilizes the closing price of our Common Stock as of February 9, 2006. At our 2006 Annual Meeting of Stockholders, a proposal to implement a new combined plan to replace both the Goodrich Petroleum Corporation 1995 Stock Option Plan and the Goodrich Petroleum Corporation 1997 Director Compensation Plan was approved.

Prior to the expiration of the 1995 Stock Option Plan, the two Goodrich plans had authorized grants of options to purchase up to a combined total of 2,300,000 shares of authorized but unissued common stock. Stock options under both plans were granted with an exercise price equal to the stock s fair market value at the date of grant, and all employee stock options granted under the 1995 Stock Option Plan generally had ten year terms and three year pro rata vesting. Share options granted under the Director Plan generally became exercisable immediately and expire, if not exercised, ten years thereafter.

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan ), at our annual meeting of stockholders. The 2006 Plan is similar to and replaces our previously adopted 1995 Incentive

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Plan (the 1995 Plan ) and 1997 Non-Employee Directors Stock Option Plan (the Directors Plan ). No further awards will be granted under the previously adopted plans, however, those plans shall continue to apply to and govern awards made thereunder. Under the 2006 Plan, a maximum of 2.0 million new shares are reserved for issuance as awards of share options to officers, employees and non-employee directors. Share options granted to officers and employees will generally become exercisable in one-third increments over a three year period and to the extent not exercised, expire on the tenth anniversary of the date of grant. Share options granted to non-employee directors will usually be immediately exercisable and to the extent not exercised, expire on the tenth anniversary of the date of grant. The exercise price of share options granted under the 2006 Plan will equal the market value of the underlying stock on the date of grant.

At December 31, 2006, options to purchase 100,000 shares of our common stock were outstanding under the 2006 Plan and options to purchase 923,500 shares of our common stock were outstanding under the 1995 Plan and the Directors Plan. In order to satisfy share option exercises, shares are issued from authorized but unissued common stock.

A summary of stock option activity is as follows:

| | Number of Options | Weighted Average Exercise Price | Range of Exercise Price | Weighted Average Remaining Contractual Life |
|---|---|---|---|---|
| Outstanding, January 1, 2004 | 236,813 | | $ 0.75 to $5.85 | 7.7 yrs |
| Granted 1995 stock option plan | 220,000 | 16.46 | | |
| Exercised 1995 stock option plan | (2,750) | 2.90 | | |
| Exercised 1997 director compensation plan | (43,563) | 3.74 | | |
| Outstanding, December 31, 2004 | 410,500 | | $ 0.75 to $16.46 | 8.5 yrs |
| Granted 1997 director compensation plan | 150,000 | 19.78 | | |
| Exercised 1995 stock option plan | (25,000) | 2.88 | | |
| Exercised 1997 director compensation plan | (16,000) | 4.92 | | |
| Outstanding, December 31, 2005 | 519,500 | 13.70 | $ 0.75 to $19.78 | 8.4 yrs |
| Granted 2006 stock option plan | 625,000 | 24.10 | | |
| Exercised 1995 stock option plan | (66,000) | 7.23 | | |

| | | | | |
|---|---|---|---|---|
| Forfeited 1995 stock option plan | (55,000) | 22.13 | | |
| Outstanding, December 31, 2006 | 1,023,500 | 20.01 | $ .75 to $27.81 | 8.2 yrs |
| Exercisable, December 31, 2004 | 169,500 | 3.20 | | |
| Exercisable, December 31, 2005 | 372,100 | 12.60 | | |
| Exercisable, December 31, 2006 | 492,167 | 16.36 | | |

*Adoption of New Accounting Pronouncement*

Effective January 1, 2006 we adopted SFAS 123R, which required us to measure the cost of stock based compensation granted, including stock options and restricted stock, based on the fair market value of the award as of the grant date, net of estimated forfeitures. SFAS 123R supersedes SFAS 123 and APB 25. We adopted SFAS 123R using the modified prospective application method of adoption, which required us to record compensation cost related to unvested stock awards as of December 31, 2005, by recognizing the unamortized grant date fair value of these awards over the remaining service periods of those awards with no change in historical reported earnings. Awards granted after December 31, 2005, are valued at fair value in accordance with provisions of SFAS 123R and recognized on a straight line basis over the service periods of each award. We estimated forfeiture rates for all unvested awards based on our historical experience. The January 1, 2006,

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

balance of unamortized restricted stock awards of $2.1 million was reclassified against additional paid-in-capital upon adoption of SFAS 123R. In fiscal 2006 and future periods, common stock par value will be recorded when the restricted stock is issued and additional paid-in-capital will be increased as the restricted stock compensation cost is recognized for financial reporting purposes. Prior period financial statements have not been restated.

In 2003 we commenced granting a series of restricted share awards with three year vesting periods to eligible employees. During 2006, 2005 and 2004, we contributed $7.1 million, $1.5 million and $2.1 million, respectively, under the plan through the issuance of 215,629, 75,750 and 238,750 shares, respectively, of our common stock. During 2006, 2005 and 2004, $2.1 million, $1.1 million and $0.6 million, respectively, were charged to compensation expense related to the restricted share awards. During 2006, 2005 and 2004, we recorded credits to the contra equity account of $0.4 million, $0.1 million and $0.2 million, respectively, for the value of 18,162, 12,832 and 28,918 shares, respectively, of non-vested restricted share awards that were forfeited by terminated employees. The fair value of restricted stock vested during 2006, 2005, and 2004 were $1.4 million, $0.8 million, and $0.2 million, respectively.

Total stock based compensation for the year ended December 31, 2006, of $5.7 million has been recognized as a component of general and administrative expenses in the accompanying Consolidated Financial Statements.

Prior to 2006, we accounted for stock-based compensation in accordance with APB 25 using the intrinsic value method, which did not require that compensation cost be recognized for our stock options provided the option exercise price was established at 100% of the common stock fair market value on the date of grant. Under APB 25, we were required to record expense over the vesting period for the value of restricted stock granted. Prior to 2006, we provided pro forma disclosure amounts in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* ( SFAS 148 ), as if the fair value method defined by SFAS 123 had been applied to our stock-based compensation. Our net loss and net loss per share for the year ended December 31, 2005, would have been greater if compensation cost related to stock options had been recorded in the financial statements based on fair value at the grant dates. Our net income and net income per share for the year ended December 31, 2004, would have been less if compensation cost related to stock options had been recorded in the financial statements based on fair values at the grant dates.

Pro forma net income (loss) as if the fair value based method had been applied to all awards for the years ended December 31, 2005 and 2004, is as follows (in thousands, except per share amounts):

| | 2005 | 2004 |
|---|---|---|
| Net income (loss) as reported | $ (17,450) | $ 18,527 |
| Add: Stock based compensation programs recorded as expense, net of tax | 743 | 579 |
| Deduct: Total stock based compensation expense, net of tax | (1,236) | (609) |
| Pro forma net income (loss) | $ (17,943) | $ 18,497 |

| | | |
|---|---|---|
| Net income (loss) applicable to common stock, as reported | $ (18,205) | $ 17,894 |
| Add: Stock based compensation programs recorded as expense, net of tax | 743 | 579 |
| Deduct: Total stock based compensation expense, net of tax | (1,236) | (609) |
| Pro forma net income (loss) applicable to common stock | $ (18,698) | $ 17,864 |
| Net income (loss) applicable to common stock per share: | | |
| Basic as reported | $ (0.78) | $ 0.92 |
| Basic pro forma | $ (0.80) | $ 0.91 |
| Diluted as reported | $ (0.78) | $ 0.88 |
| Diluted pro forma | $ (0.80) | $ 0.88 |

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**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The per share weighted average fair value of stock options granted during the years ended December 31, 2006, 2005 and 2004, were $12.98, $9.69 and $7.96, respectively, on the date of grant.

The estimated fair value of the options granted during 2006 and prior years was calculated using a Black Scholes Merton option pricing model (Black Scholes). The following schedule reflects the various assumptions included in this model as it relates to the valuation of our options:

| | December 31, 2006 | December 31, 2005 | December 31, 2004 |
|---|---|---|---|
| Risk free interest rate | 4.50-4.97% | 4.50-6.00% | 6% |
| Weighted average volatility | 54-57% | 47-57% | 46% |
| Dividend yield | 0% | 0% | 0% |
| Expected years until exercise | 5-6 | 5 | 5 |

The Black Scholes model incorporates assumptions to value stock-based awards. The risk-free rate of interest for periods within the expected term of the option is based on a zero-coupon U.S. government instrument over the expected term of the equity instrument. Expected volatility is based on the historical volatility of our common stock. We generally use the midpoint of the vesting period and the life of the grant to estimate employee option exercise timing (expected term) within the valuation model. This methodology is not materially different from our historical data on exercise timing. In the case of director options, we used historical exercise behavior. Employees and directors that have different historical exercise behavior with regard to option exercise timing and forfeiture rates are considered separately for valuation and attribution purposes.

The following table summarizes the components of our stock-based compensation programs recorded as expense (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Restricted stock: | | | |
| Pretax compensation expense | $ 2,092 | $ 1,143 | $ 891 |
| Tax benefit | (732) | (400) | (312) |
| Restricted stock expense, net of tax | $ 1,360 | $ 743 | $ 579 |
| Director stock grants: | | | |
| Pretax compensation expense | $ 1,383 | $ 240 | $ 140 |

| | | | |
|---|---|---|---|
| Tax benefit | (484) | (84) | (49) |
| Director stock grants expense, net of tax | $ 899 | $ 156 | $ 91 |
| Stock options: | | | |
| Pretax compensation expense | $ 2,487 | $ | $ |
| Tax benefit | (870) | | |
| Stock option expense, net of tax | $ 1,617 | $ | $ |
| Total share based compensation: | | | |
| Pretax compensation expense | $ 5,962 | $ 1,383 | $ 1,031 |
| Tax benefit | (2,086) | (484) | (361) |
| Total share based compensation expense, net of tax | $ 3,876 | $ 899 | $ 670 |

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, $6.6 million and $7.0 million of total unrecognized compensation cost related to restricted stock and stock options, respectively, is expected to be recognized over a weighted average period of approximately 1.9 years for restricted stock and 1.8 years for stock options.

Option activity under our stock option plans as of December 31, 2006, and changes during the 12 months then ended were as follows:

| | Shares | Wtd. Avg. Exercise Price | Remaining Contractual Term | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Outstanding at January 1, 2006 | 519,500 | $ 13.70 | | |
| Granted | 625,000 | 24.10 | | |
| Exercised | (66,000) | 7.24 | | |
| Forfeited | (55,000) | 22.13 | | |
| Outstanding at December 31, 2006 | 1,023,500 | $ 20.01 | 8.2 | $ 16,547,788 |
| Exercisable at December 31, 2006 | 492,167 | $ 16.36 | 7.5 | $ 9,755,141 |

The aggregate intrinsic value in the preceding table represents the total pre-tax intrinsic value (the difference between our closing stock price on the last trading day of the fourth quarter of 2006 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2006. The amount of aggregate intrinsic value will change based on the fair market value of our stock. The total intrinsic value of options exercised during the year ended December 31, 2006, 2005, and 2004 was $1.7 million, $0.8 million, and $0.4 million respectively.

The following table summarizes information on unvested restricted stock outstanding as of December 31, 2006:

| | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|

| | | |
|---|---|---|
| Unvested at January 1, 2006 | 263,890 | $ 11.13 |
| Vested | (182,303) | 12.03 |
| Granted | 215,629 | 32.72 |
| Forfeited | (18,162) | 21.54 |
| Unvested at December 31, 2006 | 279,054 | $ 26.12 |

In May 2006, an officer of the Company resigned and the Company accelerated the vesting of (1) options to purchase 10,000 shares and (2) 2,916 shares of previously unvested restricted stock that had been issued to the officer in 2004. The affected options are required to be accounted for as a modification of an award with a service vesting condition under SFAS 123R. The fair market value was calculated immediately prior to the modification and immediately after the modification to determine the incremental fair market value. This incremental value and the unamortized balance of the restricted stock resulted in the immediate recognition of compensation expense of approximately $0.1 million.

In December of 2006, a second officer of the company resigned and the company accelerated the vesting of 6,749 shares of previously unvested restricted stock that had been issued over the period of 2004-2005. The unamortized balance of $0.1 million was immediately recognized as compensation expense.

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**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

In December of 2006, the non-employee Directors of the company were granted a total of 26,824 shares of unrestricted stock to compensate them for past services. The charge in the financial statements relative to this grant is based on the fair market value of the shares at the grant date, and resulted in additional compensation expense of $1.1 million.

**NOTE 3 Asset Retirement Obligations**

SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets and requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2006 and 2005, is as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2006 | 2005 |
| Beginning balance | $ 7,960 | $ 6,811 |
| Liabilities incurred | 1,366 | 1,004 |
| Liabilities settled | (190) | (39) |
| Accretion expense (reflected in depletion, depreciation and amortization expense) | 438 | 363 |
| Other | (17) | (179) |
| Ending balance | 9,557 | 7,960 |
| Less: current portion | (263) | (92) |
| | $ 9,294 | $ 7,868 |

**NOTE 4 Long-Term Debt**

Long-term debt consisted of the following balances (in thousands):

| | December 31, | |
|---|---|---|
| | 2006 | 2005 |
| Senior Credit Facility (see below for rate detail) | $ 26,500 | |
| Second-lien Term Loan, bearing interest at a weighted average interest rate of 8.9% at December 31, 2005 | | 30,000 |
| 3.25% convertible senior notes due 2026 | 175,000 | |
| Total debt | 201,500 | 30,000 |
| Less current maturities | | |
| Total long-term debt | $ 201,500 | $ 30,000 |

In December 2006, we sold $175 million of 3.25% convertible senior notes due in December, 2026. With a portion of the proceeds of the note offering we fully repaid the outstanding balance of the second lien term loan. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes will be our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually and paid semi-annually on June 1 and December 1 beginning June 1, 2007.

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Prior to December 1, 2011, the notes will not be redeemable. On or after December 11, 2011, we may redeem for cash all or a portion of the notes, and the investors may require us to repay the notes on each of December 11, 2011, 2016 and 2021. The notes are convertible into shares of our common stock at a rate equal to the sum of

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (the Senior Credit Facility ) and a second lien term loan (the Term Loan ) that expanded our borrowing capabilities and extended our credit facility for an additional two years. Total lender commitments under the Senior Credit Facility were $200.0 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are subject to periodic redeterminations of the borrowing base which is currently established at **$**150.0 million, and is currently scheduled to be redetermined in March 2007, based upon our 2006 year-end reserve report. In 2006, we fully repaid $50.0 million on the Term Loan and repaid $134.5 million of the revolving borrowings under the Senior Credit Facility. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at either the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.00%, depending on borrowing base utilization. At December 31, 2006, we had $123.5 million of excess borrowing capacity under our revolving bank credit facility.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms are defined in the credit agreement. The covenants include**:**

Current Ratio of 1.0/1.0,

Interest Coverage Ratio which is not less than 3.0/1.0 for the trailing four quarters, and

Total Debt no greater than 3.5 times EBITDAX for the trailing four quarters.

EBITDAX is earnings before interest expense, income tax, DD&A and exploration expense.

As of December 31, 2006, we were in compliance with all of the financial covenants of the Amended and Restated Credit Agreement.

**NOTE 5 Net Income (Loss) Per Common Share**

Net income (loss) was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2006, 2005 and 2004. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Basic method | 24,948 | 23,333 | 19,552 |
| Stock warrants | 129 | | 478 |
| Stock options and restricted stock | 335 | | 317 |
| Dilutive method | 25,412 | 23,333 | 20,347 |

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**NOTE 6 Income Taxes**

Income tax (expense) benefit consisted of the following (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Current: | | | |
| Federal | $ | $ | $ |
| State | | | |
| | | | |
| Deferred: | | | |
| Federal | (904) | 9,397 | 1,303 |
| State | | | |
| | (904) | 9,397 | 1,303 |
| Total | $ (904) | $ 9,397 | $ 1,303 |

The following is a reconciliation of the U.S. statutory income tax rate at 35% to our income (loss) before income taxes (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Income (loss) from continuing operations | | | |
| Tax at U.S. statutory income tax | $ (890) | $ 9,397 | $ (5,625) |
| Nondeductible expenses | (14) | (5) | (6) |
| Valuation allowance and other | | 5 | 7,338 |
| | (904) | 9,397 | 1,707 |
| Income (loss) from discontinued operations | | | |

| | | | |
|---|---|---|---|
| Tax at U.S. statutory income tax | | | (404) |
| | | | (404) |
| Total tax (expense) benefit | $ (904) | $ 9,397 | $ (1,303) |

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**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2006 and 2005 are presented below (in thousands).

| | 2006 | 2005 |
|---|---|---|
| Deferred tax assets: | | |
| Differences between book and tax basis of: | | |
| Operating loss carryforwards | $ 24,599 | $ 16,064 |
| Statutory depletion carryforward | 7,034 | 7,034 |
| AMT tax credit carryforward | 1,480 | 1,480 |
| Derivative financial instruments | | 10,263 |
| Compensation | 421 | |
| Contingent liabilities and other | 462 | 466 |
| Total gross deferred tax assets | 33,996 | 35,307 |
| Less valuation allowance | (13,263) | (13,263) |
| Net deferred tax asset | 20,733 | 22,044 |
| Deferred tax liabilities: | | |
| Differences between book and tax basis of: | | |
| Property and equipment | (6,255) | (10,464) |
| Derivative financial instruments | (4,773) | |
| Total gross deferred tax liabilities | (11,028) | (10,464) |
| Net deferred tax asset | $ 9,705 | $ 11,580 |

Our stock based deferred compensation plans generated $3.5 million of additional tax deductions in 2006 which are not recognized as a component of our deferred tax asset. We recognize the benefits from excess tax stock compensation deductions after the utilization of net operating loss carryforwards generated from operations. These excess tax benefits will be recorded as additional paid in capital when realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based primarily upon the level of projections for future taxable income and the reversal of future taxable temporary differences over the periods which the deferred tax assets are deductible, management believes it is more likely than not we will realize the benefits of our deferred tax assets, net of the existing valuation allowance at December 31, 2006.

We have tax net operating loss carryforwards totaling $73.8 million which expire in years 2007 through 2026 as follows (in thousands):

| | | |
|---|---|---|
| 2007 | $ | 7,894 |
| 2008 | | 4,286 |
| 2009 | | 3,247 |
| 2010 | | 6,451 |
| 2011 | | |
| 2012 through 2026 | | 51,907 |
| Total | $ | 73,785 |

An ownership change in accordance with Internal Revenue Code (IRC) § 382, occurred in August 1995 and again in August 2000. The net operating losses (NOLs) generated prior to August 1995 are subject to an annual

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

IRC § 382 limitation of $1.7 million. The IRC § 382 annual limitation for the ownership change in August 2000 is $3.6 million. The latter IRC § 382 ownership change limitation is a cumulative limitation and does not eliminate or increase the limitation on the pre-August 1995 NOLs. The NOLs generated after August 1995 and prior to August 2000, are subject to an annual limitation of $3.6 million less the annual amount utilized for pre-August 1995 NOLs. It should be noted that the same IRC § 382 limitations apply to the alternative minimum tax net operating loss carryforwards, depletion carryforwards, and alternative minimum tax credit carryforwards. The minimum tax credit carryforward ( MTC ) of $1.5 million as of December 31, 2006, will not begin to be utilized until after the available NOLs have been utilized or expired and when regular tax exceeds the current year alternative minimum tax. The unused annual IRC § 382 limitations can be carried over to subsequent years.

**NOTE 7 Stockholders Equity**

*Common Stock* At December 31, 2006, a total of 7,733,613 unissued shares of Goodrich common stock were reserved for the following: (a) 1,023,500 shares for the exercise of stock options; (b) 3,587,850 shares for the conversion of Series B convertible preferred stock; and (c) 3,122,263 shares for the conversion of the 3.25% convertible senior notes. Stock warrants issued in connection with a September 1999 private placement of convertible notes and subsidiary securities at exercise prices ranging from $0.9375 to $1.50 per share expired in September 2006. Each warrant was exercisable into one share of common stock upon payment of the exercise price, however, the holders of the stock warrants could, in certain circumstances, elect a cashless exercise whereby additional in the money warrants could be tendered to cover the exercise price of the warrants. Pursuant to a May 2003 stock purchase agreement, the holders of 2,369,527 warrants to purchase common stock elected a cashless exercise of such warrants resulting in the issuance of 2,109,169 shares of common stock in three separate installments which closed in January, April, and July 2004. There were no further exercises of warrants to be made pursuant to the stock purchase agreement; however, in February 2005, the holder of 330,000 warrants to purchase common stock elected to exercise such warrants by paying the exercise price in cash. As of December 31, 2006, none of said warrants remained outstanding.

In May 2005, we completed a public offering of 3,710,000 shares of our common stock at an offering price of $15.40 per share resulting in net proceeds of $53.1 million, after underwriting discount and offering costs. We used the proceeds to repay all outstanding indebtedness to BNP under our previous senior credit facility in the amount of $39.5 million with the balance being added to working capital to be used primarily to fund an accelerated drilling program in the Cotton Valley Trend of East Texas and Northwest Louisiana.

*Share Lending Agreement* With the offering of the 3.25% convertible senior notes we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock. The shares of stock were lent to the affiliate of BSC under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from all such common stock offerings and lending transactions under this agreement. We will not receive any of the proceeds from these transactions. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of shares pursuant to the terms of the 3.25% convertible notes offering.

The 3,122,263 shares of common stock outstanding as of December 31, 2006, under the Share Lending Agreement are required to be returned to the Company. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. There is no impact of the shares of common stock lent under the Share Lending Agreement in the earnings per share calculation.

*Preferred Stock* Our Series A Convertible Preferred Stock (the Series A Convertible Preferred Stock ) has a par value of $1.00 per share with a liquidation preference of $10.00 per share, aggregating to $7.9 million,

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**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

and is convertible at the option of the holder at any time, unless earlier redeemed, into shares of our common stock at an initial conversion rate of 0.4167 shares of common stock per share of Series A Convertible Preferred Stock. The Series A Convertible Preferred Stock also will automatically convert to common stock if the closing price for the Series A Convertible Preferred Stock exceeds $15.00 per share for ten consecutive trading days. The Series A Convertible Preferred Stock is redeemable in whole or in part, at $12.00 per share, plus accrued and unpaid dividends. Dividends on the Series A Convertible Preferred Stock accrue at an annual rate of 8% and are cumulative. In February 2006, we fully redeemed all issued and outstanding shares of our Series A Convertible Preferred Stock at a net cost of approximately $9.3 million.

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock ) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears beginning March 15, 2006. If we fail to pay dividends on our Series B Convertible Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum will be increased by 1.0% until we have paid all dividends on our Series B Convertible Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full.

Each share is convertible at the option of the holder into our common stock, par value $0.20 per share (the Common Stock ) at any time at an initial conversion rate of 1.5946 shares of Common Stock per share, which is equivalent to an initial conversion price of approximately $31.36 per share of Common Stock. Upon conversion of the Series B Convertible Preferred Stock, we may choose to deliver the conversion value to holders in cash, shares of Common Stock, or a combination of cash and shares of Common Stock.

On or after December 21, 2010, we may, at our option, cause the Series B Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock that are issuable at the then-prevailing conversion rate, pursuant to the Company Conversion Option. We may exercise our conversion right only if, for 20 trading days within any period of 30 consecutive trading days ending on the trading day prior to the announcement of our exercise of the option, the closing price of the Common Stock equals or exceeds 130% of the then-prevailing conversion price of the Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock is non-redeemable by us.

We used the net proceeds of the offering of Series B Convertible Preferred Stock to fully repay all outstanding indebtedness under our senior revolving credit facility. The remaining net proceeds of the offering were added to our working capital to fund 2006 capital expenditures and for other general corporate purposes.

On January 23, 2006, the initial purchasers of the Series B Convertible Preferred Stock exercised their over-allotment option to purchase an additional 600,000 shares at the same price per share, resulting in net proceeds of $29.0 million, which was used to fund our 2006 capital expenditure program.

**NOTE 8 Hedging Activities**

*Commodity Hedging Activity*

We enter into swap contracts, costless collars or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We consider these to be hedging activities and, as such, monthly settlements on these contracts are reflected in our crude oil and natural gas sales, provided the contracts are deemed to be effective hedges under FAS 133. Our strategy, which is administered by the Hedging

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**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of December 31, 2006, the commodity hedges we utilized were in the form of: (a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices; and (b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price. Hedge ineffectiveness results from difference changes in the NYMEX contract terms and the physical location, grade and quality of our oil and gas production. As of December 31, 2006, our open forward positions on our outstanding commodity hedging contracts, all of which were with either BNP or Bank of Montreal (BMO), was as follows:

| Swaps | Volume | Average Price |
|---|---|---|
| Natural gas (MMBtu/day) | | |
| 1Q 2007 | 10,000 | $ 7.77 |
| Oil (Bbl/day) | | |
| 1Q 2007 | 400 | $ 53.35 |
| 2Q 2007 | 400 | 53.35 |
| 3Q 2007 | 400 | 53.35 |
| 4Q 2007 | 400 | 53.35 |

| Collars | Volume | Floor/Cap | |
|---|---|---|---|
| Natural gas (MMBtu/day) | | | |
| 1Q 2007 | 10,000 | $ 9.00 | $10.65 |
| 2Q 2007 | 10,000 | 9.00 | $10.65 |
| 3Q 2007 | 10,000 | 9.00 | $10.65 |
| 4Q 2007 | 10,000 | 9.00 | $10.65 |
| 1Q 2007 | 15,000 | $ 7.00 | $13.60 |
| 2Q 2007 | 15,000 | 7.00 | $13.60 |
| 3Q 2007 | 15,000 | 7.00 | $13.60 |
| 4Q 2007 | 15,000 | 7.00 | $13.60 |
| 2Q 2007 | 5,000 | $ 7.00 | $13.90 |
| 3Q 2007 | 5,000 | 7.00 | $13.90 |
| 4Q 2007 | 5,000 | 7.00 | $13.90 |
| Oil (Bbl/day) | | | |
| 1Q 2007 | 400 | $60.00 | $76.50 |
| 2Q 2007 | 400 | $60.00 | $76.50 |
| 3Q 2007 | 400 | $60.00 | $76.50 |
| 4Q 2007 | 400 | $60.00 | $76.50 |

The fair value of the oil and gas hedging contracts in place at December 31, 2006, resulted in a net asset of $13.4 million. As of December 31, 2006, $1.2 million (net of $0.6 million in income taxes) of deferred losses on derivative instruments accumulated in other comprehensive loss are expected to be reclassified into earnings during the next twelve months. For the year ended December 31, 2006, we recognized in earnings a gain from derivatives not qualifying for hedge accounting in the amount of $38.1 million (also included in this gain amount are settlement payments on ineffective gas and oil hedges totaling $2.1 million in 2006). This gain was recognized because our gas hedges were deemed to be ineffective for 2006, and all of our oil hedges were deemed ineffective in the fourth quarter of 2006, accordingly, the changes in fair value of such hedges could no longer be reflected in other comprehensive loss. In the fourth quarter of 2006, we reclassified $0.7 million of

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

previously deferred losses (net of $0.4 million in income taxes) from accumulated other comprehensive loss to loss on derivatives not qualifying for hedge accounting as the cash flow of the hedged items was recognized.

Subsequent to year end, we unwound the oil collar for 400 barrels per day referenced above. As a result, we expect to recognize a gain of $0.9 million in the first quarter of 2007. Subsequent to year end, we have entered into a series of physical sales contracts which will result in us selling approximately 18,500 MMbtu of gas per day in calendar year 2008 for an average price of $8.01 MMbtu before transportation charges.

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

*Interest Rate Swaps*

We have a variable-rate debt obligation that exposes us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At December 31, 2006, we had the following interest rate swaps in place with BNP (in millions):

| Effective Date | Maturity Date | LIBOR Swap Rate | Notional Amount |
|---|---|---|---|
| 02/27/06 | 02/26/07 | 4.08% | 23.0 |
| 02/27/06 | 02/26/07 | 4.85% | 17.0 |
| 02/27/07 | 02/26/09 | 4.86% | 40.0 |

The fair value of the interest rate swap contracts in place at December 31, 2006, resulted in an asset of $0.2 million. For the years ended December 31, 2006 and 2005, our earnings were not significantly affected by cash flow hedging ineffectiveness of the interest rates swaps.

**NOTE 9 Fair Value of Financial Instruments**

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments* ( SFAS 107 ). The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. The carrying amounts and fair values of the other financial instruments and derivatives at December 31, 2006 and 2005, are as follows (in thousands):

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | **Carrying Amount** | **Fair Value** | **Carrying Amount** | **Fair Value** |
| Second Lien Term Loan | $ 0 | $ 0 | $ 30,000 | $ 30,000 |
| Senior Credit Facility | 26,500 | 26,500 | | |
| 3.25% Convertible Senior Notes | 175,000 | 170,240 | | |
| Derivative assets (liabilities) | | | | |
| Oil | (1,446) | (1,446) | (4,810) | (4,810) |
| Gas | 14,865 | 14,865 | (24,620) | (24,620) |
| Interest rate | 219 | 219 | 107 | 107 |

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**NOTE 10 Commitments and Contingencies**

*Operating Leases* We have commitments under an operating lease agreement for office space. Total rent expense for the years ended December 31, 2006, 2005, and 2004, was approximately $0.6 million, $0.4 million, and $0.3 million respectively. We also have non-cancellable drilling rig commitments with various term end dates through 2009.

*Transportation Contracts* We have entered into two gas gathering and processing agreements where we are obligated to pay a minimum amount, as calculated on a yearly amount, or pay deficiencies at a specified gathering fee rate. Our production committed to these contracts is expected to exceed the minimum yearly volumes provided in the contracts, therefore avoiding payments for deficiencies.

In 2007 we purchased acreage that was committed to a gas gathering agreement where we have a four year obligation to pay a minimum amount, as calculated on a yearly amount, or pay deficiencies at a specified gathering fee rate. The first year of the contract commitment began on September 1, 2006. Our potential share of the minimum yearly amount ranges from approximately $0.1 million in the first year to approximately $0.5 million in the fourth year. The potential effect of this agreement is not included in the table below since our share of the commitment will not be determined until well(s) are drilled in 2007.

At December 31, 2006, future minimum rental payments due, drilling rig commitments, and transportation contract commitments are as follows:

| | | Payments due by Period | | | | | After |
|---|---|---|---|---|---|---|---|
| | Total | 2007 | 2008 | 2009 | 2010 | 2011 | 2011 |
| | | | (in thousands) | | | | |
| Operating leases for office space | $ 1,992 | $ 701 | $ 710 | $ 491 | $ 48 | $ 42 | |
| Drilling rig commitments | 80,247 | 45,983 | 24,956 | 9,308 | | | |
| Transportation contracts | 2,159 | 758 | 540 | 540 | 321 | | |
| Total (1) | $ 84,398 | $ 47,442 | $ 26,206 | $ 10,339 | $ 369 | $ 42 | $ |

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $9.6 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3.

*Contingencies* In July 2005, we received a Notice of Proposed Tax Due from the State of Louisiana asserting that we underpaid our Louisiana franchise taxes for the years 1998 through 2004 in the amount of $0.5 million. The Notice of Proposed Tax Due includes additional assessments of penalties and interest in the amount of $0.4 million for a total asserted liability of $0.9 million. We believe that we have fully paid our Louisiana franchise taxes for the years in question; therefore, we intend to vigorously contest the Notice of Proposed Tax Due. We have commenced our analysis of this contingency and have not recorded any provision for possible payment of additional Louisiana franchise taxes nor any related penalties and interest.

*Litigation* In the third quarter of 2004, we recognized a non-recurring gain in the amount of $2.1 million, reflecting the proceeds of a successful litigation judgment. We commenced the litigation as plaintiff in February 2000 against the operator of a South Louisiana property which was jointly acquired by us and the defendant in

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

September 1999. The judgment provided for recovery of our damages and a portion of our attorneys fees as well as interest calculated on our damages.

We are party to additional lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our financial position or results of operations.

**NOTE 11 Related Party Transactions**

On March 12, 2002, we completed the sale of a 30% working interest in the existing production and shallow rights, and a 15% working interest in the deep rights below 10,600 feet, in our Burrwood and West Delta 83 fields for $12.0 million to Malloy Energy Company, LLC ( MEC ), led by Patrick E. Malloy, III and participated in by Sheldon Appel, each of whom were members of our Board of Directors at that time, as well as Josiah Austin, who subsequently became a member of our Board of Directors. Mr. Malloy is now Chairman of our Board of Directors and Mr. Appel retired from the Board of Directors in February 2004.

Subsequent to the acquisition of a 30% working interest in the Burrwood and West Delta 83 fields in March 2002, MEC acquired an approximate 30% working interest in three other fields we operated in 2003 and 2004. In accordance with industry standard joint operating agreements, we bill MEC for its share of the capital and operating costs of the three fields on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $1.3 million and $0.5 million, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by MEC to us in the month subsequent to billing and the affiliate is current on payment of its billings.

We also serve as the operator for a number of other oil and gas wells owned by an affiliate of MEC in which we own a 7% after payout working interest. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were $19,000 and $78,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month subsequent to billing and the affiliate is current on payment of its billings.

Additionally, we also serve as the operator for a number of other oil and gas wells owned by an affiliate of MEC whereby we do not have a working interest. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2006 and 2005, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were $81,000 and $272,000, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month subsequent to billing and the affiliate is current on payment of its billings.

**NOTE 12 Acquisitions and Divestitures**

On February 7, 2007, we announced the acquisition of drilling and development rights to acreage located in the Angelina River play. We acquired a 60% working interest in the acreage and will operate the joint venture. The acquisition was completed in two separate transactions. In the initial transaction, we acquired a 40% working interest for $2.0 million from a private company. We also agreed to carry the private company for a

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

20% working interest in the drilling of five wells. In the second transaction, we are purchasing the remaining 20% working interest in the acreage in a like-kind exchange for our 30% interest in the Mary Blevins field.

On January 12, 2007, the Company and Malloy Energy entered into a Purchase and Sale Agreement with a private company for the sale of substantially all of its oil and gas properties in South Louisiana. The total sales price for the company s interest in the oil and gas properties will be approximately $100 million. The total sales price for Malloy Energy s interests in these properties was approximately $30 million. See Note 11 Related Party Transactions for additional information regarding Malloy Energy. Both the company and Malloy Energy s total consideration will be reduced by an amount equal to its proportionate share of the greater of $20 million or normal closing adjustments. The effective date of the transaction is July 1, 2006 and we expect to close the sale in late March, 2007. Subsequent to December 31, 2006, the company s interest in oil and gas properties in South Louisiana met the criteria for reporting as held for sale. The company expects to complete the sale in the first quarter of 2007. Mr. Malloy is Chairman of our Board of Directors. As of December 31, 2006, the carrying value of the assets and liabilities to be disposed of was approximately $69 million.

On December 6, 2006, we closed on the acquisition of additional interests in the Dirgin-Beckville field in the Cotton Valley Trend for $6.1 million from a private company. With this acquisition, we now own an approximate 99% working interest in this field.

In October 2004, we sold our operated interests in the Marholl and Sean Andrew fields, along with our non-operated interests in the Ackerly field, all of which were located in West Texas, for gross proceeds of approximately $2.1 million. We realized a gain of $0.9 million on the sale of these non-core properties. The results of operations of these sold properties, including the gain on sale, have been presented as discontinued operations in the accompanying consolidated statement of operations.

Results for these properties reported as discontinued operations were as follows (in thousands):

| | Year Ended December 31, 2004 |
|---|---|
| Oil and gas sales | $ 566 |
| Operating expenses | (290) |
| Gain on sale | 877 |
| Income before income taxes | 1,153 |
| Income tax expense | (404) |
| Income from discontinued operations | $ 749 |

**NOTE 13 Oil and Gas Producing Activities (Unaudited)**

*Capitalized Costs Related to Oil and Gas Producing Activities*

The table below reflects our capitalized costs related to oil and gas producing activities at December 31, 2006, and 2005 (in thousands):

| | 2006 | 2005 |
|---|---|---|
| Proved properties | $ 555,013 | $ 301,842 |
| Unproved properties | 20,653 | 14,444 |
| | 575,666 | 316,286 |
| Less accumulated depreciation, depletion and amortization | (155,204) | (73,291) |
| Net oil and gas properties | $ 420,462 | $ 242,995 |

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Costs Incurred*

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Property Acquisition | | | |
| Unproved | $ 8,569 | $ 9,216 | $ 5,528 |
| Proved | 6,120 | | |
| Exploration | 12,263 | 14,021 | 4,874 |
| Development (1) | 244,240 | 143,574 | 36,351 |
| | $ 271,192 | $ 166,811 | $ 46,753 |

(1) Includes asset retirement costs of $1.3 million in 2006, $1.1 million in 2005 and $0.4 million in 2004.

*Oil and Natural Gas Reserves*

All of our reserve information related to crude oil, condensate, and natural gas liquids and natural gas was compiled based on evaluations performed by Netherland, Sewell & Associates, Inc. as of December 31, 2006 and 2005. All of the subject reserves are located in the continental United States.

Many assumptions and judgmental decisions are required to estimate reserves. Quantities reported are considered reasonable but are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other factors.

Regulations published by the SEC define proved reserves as those volumes of crude oil, condensate, and 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 volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those volumes expected to be recovered as a result of making additional investments by drilling new wells on acreage offsetting productive units or recompleting existing wells.

The following table sets forth our net proved oil and gas reserves at December 31, 2006, 2005 and 2004 and the changes in net proved oil and gas reserves for the years ended December 31, 2006, 2005 and 2004:

| | Natural Gas (MMcf) | | | Oil (MBbls) | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| Proved Reserves at beginning of period | 142,963 | 67,682 | 30,903 | 4,973 | 5,589 | 7,805 |
| Revisions of previous estimates (1) | (66,409) | (10,382) | (6,666) | (1,612) | (648) | (3,466) |
| Extensions, discoveries and other additions (2) | 115,732 | 91,900 | 48,322 | 311 | 440 | 1,987 |
| Purchases of minerals in place | 7,727 | | | 3 | | |
| Sales of minerals in place | | | (54) | | | (249) |
| Production | (13,001) | (6,237) | (4,823) | (474) | (408) | (488) |
| Proved Reserves at end of period | 187,012 | 142,963 | 67,682 | 3,201 | 4,973 | 5,589 |

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

| | Natural Gas (MMcf) | | | Oil (MBbls) | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| Proved developed: | | | | | | |
| Beginning of period | 56,700 | 24,362 | 23,429 | 1,796 | 2,228 | 3,601 |
| End of period | 76,679 | 56,700 | 24,362 | 1,862 | 1,796 | 2,228 |

(1) Revisions of previous estimates were negative on an overall basis in 2006, 2005 and 2004 related to the following: (a) with respect to 2006, the primary cause of the revisions was the significant pricing difference between December 31, 2006 and December 31, 2005, which caused a number of our proved undeveloped locations in the Cotton Valley area to become uneconomic at the lower prices, as well as some volume revisions in these same properties and in South Louisiana as a result of updated production performance, and (b) with respect to 2005 and 2004, the premature depletion or decline in production from our South Louisiana wells which had larger estimates of producible reserves at the previous reporting period and new and/or revised interpretations of technical data from recently drilled wells in that region, updated production performance from existing and offset wells, and/or the results of enhanced 3-D seismic evaluations.

(2) Extensions, discoveries and other reserve additions were positive on an overall basis in 2006, primarily related to our continued drilling activities on existing and newly acquired properties in the Cotton Valley Trend of East Texas and North Louisiana. The main reason for the increases in 2005 and 2004 was the commencement of our Cotton Valley drilling program in the first quarter of 2004 which resulted in a substantial volume of both proved developed and proved undeveloped reserves being recorded in those years.

The following table summarizes our combined oil and gas reserve information on an MMcfe basis.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Total proved | 206,217 | 172,799 | 101,216 |
| Proved developed | 87,852 | 67,474 | 37,732 |

*Standardized Measure*

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves as of year-end is shown below (in thousands):

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Future revenues | $ 1,190,367 | $ 1,798,972 | $ 654,543 |

| | | | |
|---|---|---|---|
| Future lease operating expenses and production taxes | (409,775) | (379,872) | (151,186) |
| Future development costs (1) | (337,576) | (245,868) | (86,919) |
| Future income tax expense | (28,764) | (353,472) | (104,870) |
| Future net cash flows | 414,252 | 819,760 | 311,568 |
| 10% annual discount for estimated timing of cash flows | (213,971) | (409,140) | (130,890) |
| Standardized measure of discounted future net cash flows | $ 200,281 | $ 410,620 | $ 180,678 |
| Average price used to calculate reserves (2) | | | |
| Natural gas (per Mcf) | $ 5.64 | $ 10.54 | $ 6.14 |
| Oil (per Bbl) | $ 57.75 | $ 58.80 | $ 42.72 |

(1) Includes cumulative asset retirement obligations of $9.6 million, $8.0 million and $6.8 million in 2006, 2005 and 2004, respectively.

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**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(2) These average prices, used to estimate our reserves at these dates, reflect applicable transportation and quality differentials on a well-by-well basis.

Future revenues are computed by applying year-end prices of oil and gas to the year-end estimated future production of proved oil and gas reserves. The base prices used for the PV-10 calculation were public market prices on December 31 adjusted by differentials to those market prices. These price adjustments were done on a property-by-property basis for the quality of the oil and natural gas and for transportation to the appropriate location. Estimates of future development and production costs are based on year-end costs and assume continuation of existing economic conditions and year-end prices. We will incur significant capital in the development of our Cotton Valley Trend properties. We believe with reasonable certainty that we will be able to obtain such capital in the normal course of business. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

*Changes in Standardized Measure*

The following are the principal sources of change in the standardized measure of discounted net cash flows for the years shown (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Net changes in prices and production costs related to future production | $ (360,635) | $ 185,709 | $ 84,156 |
| Sales and transfers of oil and gas produced, net of production costs | (81,813) | (53,845) | (34,354) |
| Net change due to revisions in quantity estimates | (70,212) | (48,540) | (27,462) |
| Net change due to extensions, discoveries and improved recovery | 122,144 | 321,529 | 60,239 |
| Net change due to purchases and sales of minerals in place | 8,044 | | (4,278) |
| Future development costs | (44,339) | (79,618) | (53,739) |
| Net change in income taxes | 142,131 | (124,526) | (22,640) |
| Accretion of discount | 58,768 | 24,148 | 21,462 |
| Change in production rates (timing) and other | 15,573 | 5,085 | (6,680) |
| | $ (210,339) | $ 229,942 | $ 16,704 |

**GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**NOTE 14 Summarized Quarterly Financial Data (Unaudited)**

(In Thousands, Except Per Share Amounts)

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| 2006 | | | | | |
| Revenues | $ 25,251 | $ 30,626 | $ 29,435 | $ 30,842 | $ 116,154 |
| Operating income | 4,986 | 2,234 | (93) | (34,255) | (27,128) |
| Net income (loss) | 11,592 | 4,298 | 8,181 | (22,432) | 1,639(2) |
| Net income applicable to common stock | 8,575 | 2,777 | 6,670 | (23,944) | (5,922)(2) |
| Basic income per average common share (1) | 0.34 | 0.11 | 0.27 | (0.90) | 0.07 |
| Diluted income per average common share (1) | 0.34 | 0.11 | 0.27 | (0.90) | 0.06 |
| 2005 | | | | | |
| Revenues | $ 12,823 | $ 13,541 | $ 17,537 | $ 25,502 | $ 69,403 |
| Operating income | 691 | 104 | 3,040 | 9,357 | 13,192 |
| Net income (loss) | (6,151) | (445) | (19,474) | 8,620 | (17,450)(3) |
| Net income applicable to common stock | (6,309) | (603) | (19,632) | 8,339 | (18,205)(3) |
| Basic income per average common share (1) | (0.30) | (0.02) | (0.79) | 0.35 | (0.75) |
| Diluted income per average common share (1) | (0.30) | (0.02) | (0.79) | 0.34 | (0.75) |

(1) The sum of the per share amounts per quarter does not equal the year due to the changes in the average number of common shares outstanding.
(2) Includes a $40.2 million unrealized gain on derivatives not qualifying for hedge accounting.
(3) Includes a $27.0 million unrealized loss on derivatives not qualifying for hedge accounting.