GOODRICH PETROLEUM CORP
Form 10-K
March 13, 2008
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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, 2007

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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

(713) 780-9494 (Registrant s telephone number, including area code)

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

Common Stock, par value $0.20 per share	New York Stock Exchange
(Title of Class)	*(Name of Exchange)*

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

Series B Preferred Stock, $1.00 par value

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Small reporting company ¨

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, 2007) the last business day of the registrant s most recently completed second fiscal quarter was approximately $535 million. The number of shares of the registrant s common stock outstanding as of March 10, 2008 was 34,832,203.

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, 2007

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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. We own working interests in 301 active oil and gas wells located in 26 fields in five states. At December 31, 2007, Goodrich had estimated proved reserves of approximately 346.9 Bcf of natural gas and 1.8 MMBbls of oil and condensate, or an aggregate of 357.8 Bcfe with a pre-tax present value of future net cash flows, discounted at 10%, or PV-10, of $312.7 million and a related standardized measure of discounted future net cash flows of $284.1 million, which reflects the after-tax present value of discounted future net cash flows. See Note 14 Oil and Gas Producing Activities (Unaudited) Oil and Natural Gas Reserves to our consolidated financial statements for a reconciliation of PV-10 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 production and reserves. 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. We currently estimate that our Cotton Valley trend inventory includes approximately 2,000 gross non-proved drilling locations, based on anticipated spacing for wells as follows:

- 40 acres, vertical wells only at our South Henderson and Bethany-Longstreet fields;

- 20 acres, vertical wells only at our Dirgin-Beckville field and southeasten proportion of North Minden;

60 acres, vertical wells only at our Cotton, Cotton South and Bethune prospects in Angelina River trend primarily targeting the Travis Peak sands; and

160 acres, horizontal James Lime wells at our Cotton, Cotton South and Bethune prospects only in Angelina River trend.

Use of Advanced Technologies. We continually perform field studies of our existing properties and reevaluate exploration and development opportunities using advanced technologies. For example, we recently commenced drilling our fifth horizontal Cotton Valley well and fifth James Lime horizontal well in the Cotton Valley trend and continue to monitor results. With continued success, we intend to pursue additional horizontal drilling opportunities in the future.

Expand Acreage Position in the Cotton Valley trend. We have increased our acreage position from approximately 163,200 gross (102,000 net) acres at December 31, 2006 to approximately 181,600 gross

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(114,800 net) acres as of December 31, 2007. 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 that exhibits similar characteristics to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on Low Operating Costs. We continually seek ways to minimize lease operating expenses and overhead expenses. We will continue to seek to control costs to the greatest extent possible by controlling our operations. As we continue to develop our Cotton Valley trend properties, our overall operating costs per Mcfe are expected to decrease, due primarily to efficiencies gained as we reach critical mass in each of our primary areas. As an example, a recently installed low pressure gathering system within our Dirgin-Beckville field of East Texas has eliminated the majority of our trucking expenditures associated with salt water disposal in the field, resulting in an almost 50% savings for this expense. Additionally, in March 2007, we sold most of our assets in South Louisiana which had higher operating costs than our Cotton Valley trend properties.

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 instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Oil and Gas Operations and Properties

Cotton Valley Trend

Overview. As of December 31, 2007, almost all of our proved oil and gas reserves were in the Cotton Valley trend of East Texas and Northwest Louisiana. We spent approximately 99%, or $297.4 million, of our 2007 capital expenditures of $300.2 million in the Cotton Valley trend. Of the $300.2 million of capital expenditures for the year, $274.2 million was associated with drilling and completion costs, $15.3 million for facilities and infrastructure and $10.7 million for leasehold acquisition. As of year-end, we have acquired or farmed in leases totaling approximately 181,600 gross (114,800 net) acres and are continually attempting to acquire additional acreage in the area. Company operated acreage comprised 137,800 gross acres (with an average working interest of approximately 85%) and non-operated acreage comprised 43,800 gross acres (with an average working interest of approximately 40%). As of the year end, we have drilled and completed 258 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 12,300 gross (11,400 net) acres with an average working interest of approximately 99%. As of December 31, 2007, we had successfully drilled and completed 65 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 31,800 gross (27,200 net) acres with a working interest of approximately 92%. As of December 31, 2007, we had successfully drilled and completed 88 Cotton Valley trend wells and one unsuccessful well 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 13,200 gross (10,500 net) acres with an average working interest of approximately 96%. As of December 31, 2007, we had successfully drilled and completed 21 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, 2007, we had successfully drilled and completed 32 Cotton Valley trend wells in

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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 now hold 27,900 gross (18,700 net) acres in the field. We have an average 69% working interest in the Bethany-Longstreet field.

Angelina River. The Angelina River area is located in Angelina, Nacogdoches, and Cherokee Counties in Texas. We had acquired approximately 67,600 gross (33,000 net) acres in the area as of December 31, 2007. We own an average 61% working interest in the acreage. We currently are the operator of 44,200 gross acres, while owning a 40% non-operated interest in 23,400 gross acres. At year end, we had successfully drilled and completed 38 wells and recompleted one well in the field.

Other Cotton Valley Trend. We also own 28,800 gross (14,000 net) acres in six separate areas of the Cotton Valley trend in Harrison, Smith and Upshur Counties, Texas, and Caddo and Bienville Parishes, Louisiana, with an average working interest of approximately 63%. We have successfully drilled and completed 13 wells in these areas.

Production and Reserves. For the wells completed to date in the Cotton Valley trend, the average initial gross production rate per well was approximately 1,800 Mcfe per day. This average initial gross production rate is approximately 100 Mcfe per day higher than that calculated on a similar basis at the end of 2006. Initial production from the Cotton Valley trend wells commenced in June 2004 and for the quarter ended December 31, 2007, gross production from the initial and subsequently drilled wells averaged approximately 85,900 Mcfe per day. Net production averaged approximately 50,200 Mcfe per day (Mcfe/d) for the fourth quarter of 2007.

	December 31, 2007		Fourth Quarter 2007	
	Proved Reserves	% of Total	Net Average Daily Production	% of Total
	(Mmcfe)		(Mcfe/d)	
Dirgin-Beckville	117,956	33%	13,329	26%
North Minden	104,389	29%	10,026	20%
South Henderson	29,782	8%	5,303	10%
Bethany-Longstreet	36,987	10%	9,074	18%
Angelina River	61,079	17%	8,904	18%
Other Cotton Valley trend	5,071	2%	3,605	7%
Total Cotton Valley trend	355,264	99%	50,241	99%
Other	2,528	1%	214	1%
Total	357,792	100%	50,455	100%

South Louisiana

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 with the same effective date. See Note 11 Related Party Transactions to our consolidated financial statements for additional information regarding Malloy Energy. Both the Company s and Malloy Energy s total consideration was reduced by an amount equal to its proportionate share of normal closing adjustments. The effective date of the transaction was July 1, 2006 and the closing date of the sale was March 20, 2007. The sale resulted in net proceeds of $72.3 million, after normal closing adjustments. We recognized a before tax gain of $14.9 million ($9.7 million gain net of tax) on the sale. Average daily production for these properties for the fiscal year-ending December 31, 2006, was approximately 12,904 Mcfe or about 30% of the Company s total production for 2006. At December 31, 2006, these properties had estimated proved reserves of approximately 15.7 Bcf of natural gas and 2.7 Mmbls of oil and condensate, or an aggregate of 31.7 Bcfe with a PV-10 of $105.5 million.

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We continue to treat the St. Gabriel, Bayou Bouillon and Plumb Bob fields as held for sale, which collectively represent less than 1% of our total equivalent proved reserves at December 31, 2007.

Other Properties

As of December 31, 2007, we maintain ownership interests in acreage and/or wells in several additional fields including (i) the Midway field, located in San Patricio County, Texas, (ii) the Mott Slough field, located in Wharton County, Texas and (iii) 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, 2007 and 2006, 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 14 Oil and Gas Producing Activities (Unaudited) to our consolidated financial statements for additional information. We did not file any reports during the year ended December 31, 2007, with any federal authority or agency with respect to our estimates of oil and natural gas reserves.

	December 31, 2007				
	Oil	Natural Gas	Total	Future Net Revenues	PV-10 (1)
	(Mbbls)	(Mmcf)	(Mmcfe)	($000)	($000)
Proved Developed	282	108,077	109,769	$ 425,770	$ 266,819
Proved Undeveloped	1,528	238,855	248,023	469,188	45,865
Total Proved	1,810	346,932	357,792	$ 894,958	$ 312,684

	December 31, 2006				
	Oil	Natural Gas	Total	Future Net Revenues	PV-10 (1)
	(Mbls)	(MMcf)	(MMcfe)	($000)	($000)
Proved Developed	1,862	76,679	87,852	$ 301,146	$ 208,490
Proved Undeveloped	1,339	110,333	118,365	141,871	5,697
Total Proved	3,201	187,012	206,217	$ 443,017	$ 214,187

(1) PV-10 represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves may be considered a non-GAAP financial measure as defined by the SEC. We believe that the

presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. Our standard measure of discounted future net cash flows of proved reserves, or standardized measure, as of December 31, 2007 was $284.1 million. See Note 14 Oil and Gas Producing Activities (Unaudited) Oil and Natural Gas Reserves to our consolidated financial statements for a reconciliation or PV-10 to the standardized measure of discounted future net cash flows.

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 PV-10 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, our independent reserve engineers estimates of future net revenues from our properties and the PV-10 and standardized measure 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 index prices as of December 31, 2007 and 2006, used in such estimates averaged $6.80 and $5.64 per Mcf, respectively, of natural gas and $92.50 and $57.75 per Bbl, respectively, of crude oil/condensate. These prices do not include the impact of hedging transactions, nor do they include applicable transportation and quality differentials, which are deducted from or added to the index prices on a well by well basis.

Productive Wells

The following table sets forth the number of active well bores in which we maintain ownership interests as of December 31, 2007:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Louisiana	8	5.6	46	30.4	54	36.0
Texas	6	4.4	230	200.3	236	204.7
Michigan and other	7	0.4	4	0.1	11	0.5
Total Productive Wells	21	10.4	280	230.8	301	241.2

(1) Does not include royalty or overriding royalty interests.
(2) 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, 2007. 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	12,302	8,711	40,029	22,625	52,331	31,336
Texas	70,988	53,638	60,526	31,541	131,514	85,179
Michigan	1,920	19			1,920	19
Total	85,210	62,368	100,555	54,166	185,765	116,534

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.

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Operator Activities

We operate a majority of our producing properties by value, 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,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	90	72.0	99	75.9	57	51.7
Non-Productive	1	0.7	1	1.0	1	0.4
Total	91	72.7	100	76.9	58	52.1
Exploratory Wells:						
Productive	5	3.4	4	1.6	5	3.0
Non-Productive			1	0.6	1	0.5
Total	5	3.4	5	2.2	6	3.5
Total Wells:						
Productive	95	75.4	103	77.5	62	54.7
Non-Productive	1	0.7	2	1.6	2	0.9
Total	96	76.1	105	79.1	64	55.6

At December 31, 2007, we had 11 gross development wells (8.8 net) 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, 2007.

	2007	2006	2005
Production Continuing Operations:			
Natural gas (MMcf)	15,281	10,500	3,786
Oil and condensate (MBbls)	118	106	38
Total (MMcfe)	15,991	11,135	4,012
Average Daily Net Production (Mcfe)	43,811	30,507	10,992
Production Discontinued Operations:			
Natural gas (MMcf)	531	2,501	2,451
Oil and condensate (MBbls)	86	368	370
Total (MMcfe)	1,047	4,710	4,674
Average Daily Net Production (Mcfe)	2,568	12,904	12,805
Revenue Continuing Operations (in thousands):			
Natural gas	$ 102,215	$ 67,372	$ 33,016
Oil and condensate	8,476	6,561	1,970
Total	$ 110,691	$ 73,933	$ 34,986
Average Realized Sales Price Per Unit From Continuing Operations:			
Natural gas (per Mcf)	$ 6.69	$ 6.42	$ 8.72
Oil and condensate (per Bbl)	$ 71.83	$ 62.03	$ 52.47
Total (per Mcfe)	$ 6.92	$ 6.64	$ 8.72
Other Data From Continuing Operations (per Mcfe):			
Lease operating	$ 1.40	$ 1.14	$ 0.87
Production and other taxes	$ 0.14	$ 0.30	$ 0.53
DD&A	$ 4.99	$ 3.34	$ 3.04
Exploration	$ 0.46	$ 0.53	$ 1.42

For a discussion of comparative changes in our production volumes, revenues and operating expenses for the three years ended December 31, 2007, 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 year ended December 31, 2007 was as follows:

	2007
Louis Dreyfus Corporation	31%
Shell Trading	23%
Texla Energy Management Inc.	10%

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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 10, 2008, we had 93 full-time employees in our two administrative offices and one field office, none of whom is represented by any labor union. 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. Compliance with 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 that may limit or prohibit some or all of our operations.

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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 following is a summary of the more significant existing environmental laws to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (CERCLA), also known as the Superfund law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, 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. Under CERCLA, these persons may be subject to joint and several strict liability for remediation costs at the site, natural resource damages and for the costs of certain health studies. 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), and comparable state statutes which impose 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 non-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.

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

The Federal Water Pollution Control Act, as amended, (Clean Water Act), and analogous state law, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state and federal waters. 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 including natural reservoir 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, as amended, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. 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.

In response to recent studies suggesting that emissions of certain gases, referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a cap and trade scheme of regulation of greenhouse gas emissions a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. Debate and a possible vote on this bill by the full Senate are anticipated to occur before mid-year 2008. In addition, at least one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels (*e.g.*, oil or natural gas) we produce. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain CAA programs. New federal or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the oil and gas we produce.

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.

Item 1A. ***Risk Factors***

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

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The following summarizes some, but not all, of the risks and uncertainties which may adversely affect our business, financial condition or results of operations.

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 NSA, our independent reserve engineers, and were calculated using oil and gas prices as of December 31, 2007. These prices will change and may be lower at the time of production than those prices that prevailed at the end of 2007. 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 wells;
- 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 PV-10, 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.

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

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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;
- 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 fourth horizontal well in the Cotton Valley trend. 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; a decrease in the price of natural gas or oil would adversely impact 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.

Crude oil and natural gas prices are extremely volatile. Average oil and natural gas prices fluctuated substantially during the three year period ended December 31, 2007. 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

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to, price volatility. 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 natural gas prices (price per one million British thermal units or Mmbtu) and crude oil prices (West Texas Intermediate or WTI) for 2007, as well as these prices at year-end and at March 10, 2008:

	Henry Hub Per Mmbtu
February 6, 2007 (high)	$ 9.13
September 5, 2007 (low)	5.14
December 28, 2007	6.80
March 10, 2008	9.58

	WTI Per barrel
November 20, 2007 (high)	$ 98.88
January 18, 2007 (low)	50.49
December 28, 2007	96.01
March 10, 2008	107.90

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 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.

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, 2007, we realized a gain on settled financial derivatives of $9.7 million. For the years ended December 31, 2006 and 2005, we realized a loss on settled financial derivatives of $2.1 million and $18.0 million, respectively.

For the year ended December 31, 2007, we recognized in earnings an unrealized loss on derivative instruments not qualifying for hedge accounting in the amount of $16.1 million. For financial reporting purposes, this unrealized loss was combined with a $9.7 million realized gain in 2007 resulting in a total unrealized and realized loss on derivative instruments not qualifying for hedge accounting of $6.4 million for 2007.

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. This loss was recognized because the natural gas hedges were deemed to be ineffective for 2005, 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, 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. Additionally, recent unfavorable disclosures by international financial institutions concerning the sub-prime mortgage market may lead to a contraction in credit availability, thereby impacting our ability to finance our operations. 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 unable 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 69% of our total estimated proved reserves by volume at December 31, 2007, 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.

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, 2007, 2006 and 2005, we recorded impairments of $7.7 million, $9.9 million and $0.3 million, respectively.

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 single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Approximately 99% of our estimated proved reserves at December 31, 2007, and a similar percentage of our production during 2007 were associated with our Cotton Valley trend. We sold substantially all of our assets in South Louisiana to a private company in a sale that closed in 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 or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention or natural disasters, 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 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 and second lien term loan contain 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 senior credit facility and second lien term loan. As of December 31, 2007, we were in compliance with all the financial covenants of our senior credit facility and our second lien term loan was not in existence at that time. 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 hydrocarbons and wastes due to our handling of hydrocarbons and wastes, the release of air emissions or water discharges in connection with our operations, and historical industry operations and waste disposal practices conducted by us or predecessor operators 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.

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 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.

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 before 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 and all of 2007.

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***

We are party to 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 10, 2008, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,448 with 34,832,203 shares outstanding. High and low sales prices for our common stock for each quarter during the calendar years 2007 and 2006 are as follows:

	2007		2006	
	High	Low	High	Low
First Quarter	$ 36.90	$ 28.09	$ 29.60	$ 23.58
Second Quarter	38.31	30.91	28.95	22.59
Third Quarter	41.14	28.64	35.95	26.34
Fourth Quarter	35.20	22.05	44.57	25.21

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 open market repurchases of our common stock for the year ended December 31, 2007. When an employee s restricted stock shares vest, the company (at the option of the employee) generally withholds an amount of shares necessary to cover that employees minimum income tax withholding obligation. The company then advances the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2007, we withheld 40,418 shares in this manner and paid $1.3 million to the appropriate tax authority as minimum withholding.

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,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 110,691	$ 73,933	$ 34,986	$ 3,759	$ 1,609
Other	614	838	325	151	477
	111,305	74,771	35,311	3,910	2,086
Operating Expenses					
Lease operating expense	22,465	12,688	3,494	306	431
Production and other taxes	2,272	3,345	2,136	205	166
Transportation	5,964	3,791	558		
Depreciation, depletion and amortization	79,766	37,225	12,214	1,486	900
Exploration	7,346	5,888	5,697	955	1,591
Impairment of oil and gas properties	7,696	9,886	340		335
General and administrative	20,888	17,223	8,622	5,821	5,314
(Gain) loss on sale of assets	(42)	(23)	(235)	(50)	66
Other	109				
	146,464	90,023	32,826	8,723	8,803
Operating income (loss)	(35,159)	(15,252)	2,485	(4,813)	(6,717)
Other income (expense):					
Interest expense	(11,870)	(7,845)	(2,359)	(1,110)	(1,051)
Gain (loss) on derivatives not qualifying for hedge accounting	(6,439)	38,128	(37,680)	2,317	
Loss on early extinguishment of debt		(612)			
	(18,309)	29,671	(40,039)	1,207	(1,051)
Income (loss) from continuing operations before income taxes	(53,468)	14,419	(37,554)	(3,606)	(7,768)
Income tax (expense) benefit	(3,034)	(5,120)	13,144	8,594	2,712
Income (loss) from continuing operations	(56,502)	9,299	(24,410)	4,988	(5,056)
Discontinued operations including gain on sale of assets, net of income taxes	11,469	(7,660)	6,960	13,539	8,978
Income (loss) before cumulative effect of change in accounting principle	(45,033)	1,639	(17,450)	18,527	3,922

Cumulative effect of change in accounting principle net of income taxes					(205)
Net income (loss)	(45,033)	1,639	(17,450)	18,527	3,717
Preferred stock dividends	6,047	6,016	755	633	633
Preferred stock redemption premium		1,545			
Net income (loss) applicable to common stock	$ (51,080)	$ (5,922)	$ (18,205)	$ 17,894	$ 3,084
Income (loss) per common share from continuing operations:					
Basic	$ (2.21)	$ 0.37	$ (1.05)	$ 0.26	$ (0.28)
Diluted	$ (2.21)	$ 0.37	$ (1.05)	$ 0.25	$ (0.25)
Income (loss) per common share from discontinued operations:					
Basic	0.45	(0.30)	0.30	0.69	0.50
Diluted	0.45	(0.31)	0.30	0.66	0.44
Weighted average number of common shares outstanding:					
Basic	25,578	24,948	23,333	19,552	18,064
Diluted	25,578	25,412	23,333	20,347	20,482

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	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands)				
Balance Sheet Data:					
Total assets	$ 590,118	$ 479,264	$ 296,526	$ 127,977	$ 89,182
Total long-term debt	215,500	201,500	30,000	27,000	20,000
Stockholders' equity	283,615	205,133	181,589	65,307	48,059

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

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 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

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 and Caddo Parishes, Louisiana. We continue to build our acreage position in the Cotton Valley trend and hold approximately 181,600 gross acres as of December 31, 2007. As of year end, we have drilled and completed a cumulative total of 258 Cotton Valley wells with a success rate slightly in excess of 99%. Our net production volumes from our Cotton Valley trend wells aggregated approximately 43,500 Mcfe per day in 2007, or approximately 99% of our total oil and gas production in the period.

Sale of South Louisiana Assets

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 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, with an economic effective date of July 1, 2006. As a result, we restated our financial information to reflect discontinued operations in our Current Report on Form 8-K dated August 7, 2007. The total sales price for Malloy Energy s interests in these properties was approximately $30 million with the same effective date. See Note 11 Related Party Transactions to our consolidated financial statements for additional information regarding Malloy Energy. Both the Company s and Malloy Energy s total consideration was reduced by an amount equal to its proportionate share of normal closing adjustments. The effective date of the transaction was July 1, 2006 and the closing date of the sale was March 20, 2007. The sale resulted in net proceeds of $72.3 million, after normal closing adjustments. We recognized a before tax gain of $14.9 million ($9.7 million gain net of tax) on the sale. Average daily production for these properties for the fiscal year-ending December 31, 2006, was approximately 12,904 Mcfe or about 30% of the Company s total production for 2006.

We continue to treat the St. Gabriel, Bayou Bouillon and Plumb Bob fields as held for sale.

Overview of 2007 Results

2007 Financial and operating results include:

- We increased our oil and gas production volumes on continuing operations 44% over 2006. Production averaged 43.8 MMcfe/d in 2007 compared to 30.5 MMcfe/d in 2006.

- Our 2007 oil and gas revenues from continuing operations totaled $110.7 million compared to $73.9 million in 2006, a 50% increase.

- Net cash provided by operating activities increased $20.8 million from 2006, to $85.9 million.

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We conducted drilling or completion operations on 104 gross wells in 2007, as compared to 101 gross wells in 2006.

Capital expenditures totaled $300.1 million in 2007, versus $269.4 million in 2006.

We raised $145.4 million in net proceeds from the sale of 6.4 million shares of common stock in late 2007, of which we used $21.6 million to purchase a series of capped calls.

Our borrowing base increased to $170 million, up 55% from $110 million (note the borrowing base was reduced in January 2008 to $142.5 million, upon our entering into a $75.0 million second lien term loan agreement).

Estimated proved reserves grew 74% to approximately 357.8 Bcfe (approximately 346.9 Bcf of natural gas and 1.8 MMBbls of oil and condensate), with a PV-10 of $312.7 million and a standardized measure of $284.1 million.

Our net loss from continuing operations includes a $19.7 million non-cash write down of our net deferred tax asset to zero.

Summary Operating Information:

Continuing Operations	Year End December 31,				Year End December 31,			
	2007	2006	Variance		2006	2005	Variance	
	(In thousands, except for price data)							
Revenues:								
Natural Gas	$ 102,215	$ 67,372	34,843	52%	$ 67,372	$ 33,016	$ 34,356	104%
Oil and condensate	8,476	6,561	1,915	29%	6,561	1,970	4,591	233%
Natural gas, oil and condensate	110,691	73,933	36,758	50%	73,933	34,986	38,947	111%
Operating revenues	111,305	74,771	36,534	49%	74,771	35,311	39,460	112%
Operating expenses	146,464	90,023	56,441	63%	90,023	32,826	57,197	174%
Operating income (loss)	(35,159)	(15,252)	(19,907)	(131%)	(15,252)	2,485	(17,737)	(714%)
Net Income (loss) applicable to common stock	(51,080)	(5,922)	(45,158)	(763%)	(5,922)	(18,205)	12,283	(67%)
Net Production:								
Natural Gas (MMcf)	15,281	10,500	4,781	46%	10,500	3,786	6,714	177%
Oil and condensate (MBbls)	118	106	12	11%	106	38	68	179%
Total (MMcfe)	15,991	11,135	4,856	44%	11,135	4,012	7,123	178%
Average daily production (Mcfe/d)	43,811	30,507	13,304	44%	30,507	10,992	19,515	178%
Average Realized Sales Price Per Unit:								
Natural Gas (per Mcf)	$ 6.69	$ 6.42	$ 0.27	4%	$ 6.42	$ 8.72	$ (2.30)	(26%)
Oil and condensate (per Bbl)	71.83	62.03	9.80	16%	62.03	52.47	9.56	18%
Average realized price (per Mcfe)	6.92	6.64	0.28	4%	6.64	8.72	(2.08)	(24%)

Results of Operations

Operating Income

Year ended December 31, 2007 compared to year ended December 31, 2006

Operating revenues increased 49% or $36.5 million compared to 2006, to a total of $111.3 million in 2007 due to production increases and a slight increase in average realized price per Mcfe. Production increased 44% year-to-year from 11,135 MMcfe to 15,991 MMcfe and our average realized price increased 4% from $6.64 Mcfe to $6.92 per Mcfe. The drilling and completion of 95 wells in the Cotton Valley trend led to the gains in natural gas production for 2007. Operating expenses increased 63% to $146.5 million in 2007. The primary driver behind the $56.4 million increase in operating expenses was a $42.5 million increase in depreciation, depletion and amortization (DD&A) year-to-year.

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

Operating revenues from continuing operations increased 112% or $39.5 million compared to 2005, to a total of $74.8 million in 2006. The increase resulted from a 178% increase in production volumes from 2005 to 2006. The drilling and completion of 101 operated wells in the Cotton Valley trend led to natural gas production more than doubling in 2006. The average realized price for natural gas fell in 2006 by 26% from $8.72 per Mcf to $6.42 per Mcf. The average realized oil price was strong in 2006, increasing 19%, from $51.84 per Bbl to $62.03 per Bbl.

	Year Ended December 31				Year Ended December 31			
Operating Expenses per Mcfe	**2007**	**2006**	**Variance**		**2006**	**2005**	**Variance**	
Lease operating expenses	$ 1.40	$ 1.14	$ 0.26	23%	$ 1.14	$ 0.87	$ 0.27	31%
Production and other taxes	0.14	0.30	(0.16)	(53%)	0.30	0.53	(0.23)	(43%)
Transportation	0.37	0.34	0.03	9%	0.34	0.14	0.20	143%
Depreciation, depletion and amortization	4.99	3.34	1.65	49%	3.34	3.04	0.30	10%
Exploration	0.46	0.53	(0.07)	(13%)	0.53	1.42	(0.89)	(63%)
Impairment of oil and gas properties	0.48	0.89	(0.41)	(46%)	0.89	0.08	0.81	1013%
General and administrative	1.31	1.55	(0.24)	(15%)	1.55	2.15	(0.60)	(28%)

Operating Expenses

Year ended December 31, 2007 compared to year ended December 31, 2006

Lease Operating Expenses (LOE) for 2007 increased 78% to $22.5 million from $12.7 million for 2006. Generally higher operating costs, primarily salt water disposal (SWD) and compression costs, contributed to the majority of the increase in 2007. Most of our fields experienced increases in the cost of SWD due to rising fuel costs for trucking. We did see lower SWD costs for the year in the Beckville field, beginning in June 2007, when our East Texas low pressure gathering system (LPGS) in the Beckville field became operational. The LPGS lowers SWD costs by utilizing flowlines to pipe the water to the commercial SWD wells rather than hauling the water with trucks. We have plans to reduce our SWD costs in the Bethany Longstreet and Angelina River trend fields during 2008. Higher workover costs also contributed to the higher LOE. Workover costs rose $0.13 per Mcfe with increased activity in the Beckville and North Minden fields ($2.6 million or $0.16 per Mcfe in 2007 vs. $0.3 million or $0.03 per Mcfe in 2006).

Production and other taxes of $2.3 million for 2007 consist of production tax of $1.1 million and ad valorem tax of $1.2 million. Production and ad valorem taxes in 2006 were $2.9 million and $0.4 million, respectively. Production tax in 2007 included $3.9 million of accrued Tight Gas Sands (TGS) credits for our wells in the State of Texas. These TGS credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we have been notified of the State s approval, and we anticipate that we will incur a gradually lower production tax rate in the future as we add additional Cotton Valley trend wells to our production base and as reduced rates are approved.

Ad valorem tax is assessed on the value of properties as of the first day of the year. The number of properties we owned increased from January 1, 2006 to January 1, 2007 and the assessed values for our existing properties were higher year to year. The combination of these two factors led to the increase in ad valorem taxes year to year.

Transportation expense was $6.0 million in 2007 compared to $3.8 million for 2006 as production volumes increased 44 % year-over-year. The unit cost increased nine percent (from $0.34 per Mcfe in 2006 to $0.37 per Mcfe in 2007) due to an increase in production rates from fields requiring greater transportation, and due to several contracts entered into which transported gas to higher valued markets.

DD&A expense increased to $79.8 million in 2007 from $37.2 million for 2006 primarily due to a higher DD&A rate coupled with higher levels of production. Since we use the successful efforts method of accounting, our DD&A rate is primarily a function of our capitalized drilling, completion and facilities costs divided by our proved developed reserves. Beginning in late 2004/early 2005 we embarked on an aggressive drilling program to fully develop our extensive East Texas / North Louisiana Cotton Valley trend acreage position during a period of record high costs for drilling and completion services. Additionally, to hold the majority of our acreage and thereby allow for the most prudent development plan going forward, we chose to drill many wells in the outlying areas of our acreage block, where per well results were less certain than in the initial established areas. Finally, many of our initial wells in certain fields required us to pay the costs of other industry partners to earn access to the full acreage position. As such, we believe our DD&A rate on a company-wide basis will decrease over time as we add more proved developed reserves to our asset base through the drilling of wells where we are more certain of the results and we pay only our proportionate share of the costs.

We calculated first and second quarter 2007 DD&A rates using the December 31, 2006 reserves, which did not recognize any impact of our 2007 Cotton Valley trend drilling program reserve additions. During 2007, we engaged NSA, our independent reserve engineers, to fully engineer our June 30, 2007 proved reserve estimates. This mid-year reserve report was used to calculate rates for the third and fourth quarters of 2007. As mentioned above, the DD&A rate per Mcfe based on this report was $4.77, which was lower than the rate used for the first half of this year primarily due to the inclusion of more wells drilled in our core areas during the first half of this year relative to the mix of wells in the December 31, 2006 reserve report.

Exploration expenses for 2007 increased to $7.3 million from $5.9 million for 2006. Exploration expenses on a per unit basis declined to $0.46 per Mcfe in 2007 from $0.53 per Mcfe in 2006. The increase in exploration expense year to year relates to an increase in leasehold amortization, a non-cash expense and the largest component of exploration expense. We increased our undeveloped acreage position from last year which resulted in higher leasehold cost amortization of $6.1 million for 2007, compared to $4.8 million in the same period last year.

We recorded an impairment expense of $7.7 million for the year ended December 31, 2007, $6.1 million of which related to our Alabama Bend field located in the other Cotton Valley trend leasehold area. We also recorded an impairment expense of $1.4 million and $0.3 million in the fourth and third quarters of 2007, respectively, related to two wells in a non-core area of East Texas. We recorded impairment expense in conjunction with the receipt of the independent engineer s year-end and mid-year reports on reserves.

General and administrative (G&A) expense increased to $20.9 million for 2007, compared to $17.2 million for 2006, resulting from generally higher compensation costs and a Louisiana franchise tax payment made under protest. G&A on a per unit basis decreased 17% as a result of higher production volumes in 2007. Salaries and benefits account for a large portion of total G&A. After the sale of substantially all of our properties in South Louisiana in March 2007, we had 74 employees. As of December 31, 2007, we had 86 employees. We paid $0.3 million in severance to employees in conjunction with the sale of all of our South Louisiana properties in March 2007. G&A for the year also includes a $0.3 million non-cash charge for the acceleration of vesting of options and restricted stock associated with the resignation of an officer of the Company effective August 30, 2007.

We accrued a liability for $1.0 million in March 2007, representing $0.4 million in penalties and interest and $0.6 million the State of Louisiana asserts we owe for franchise taxes (see Note 9 Discontinued Operations to our consolidated financial statements). While we paid this amount under protest in April 2007, we plan to pursue the reimbursement of the full $1.0 million. Should our efforts prevail, the amounts paid under protest would be refunded.

Our natural gas hedges were deemed ineffective beginning in 2004, consequently we have been required to reflect the change in the fair value of our natural gas hedges in earnings rather than in accumulated other comprehensive loss, a component of stockholders equity. Additionally, our oil hedges were deemed ineffective beginning in the fourth quarter of 2006. All of our hedges were marked to market in 2007. To the extent that our hedges do not qualify for hedge accounting in the future, we will likewise be exposed to volatility in earnings resulting from changes in the fair value of our hedges.

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

LOE was $12.7 million for 2006 compared to $3.5 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). Higher workover activity also contributed to a higher cost per Mcfe in 2006. The majority of this activity occurred during the fourth quarter of 2006.

Production and other taxes of $3.3 million for 2006 consist of production tax of $2.9 million and ad valorem tax of $0.4 million. Production and ad valorem taxes in 2005 were $1.8 million and $0.3 million, respectively. 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 TGS wells, allowing us to pay a lower severance tax rate for up to 10 years following certification by the State.

Transportation expense was $3.8 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. As our volumes from the Cotton Valley trend expanded over 181% during 2006, our transportation expense increased accordingly.

DD&A expense was $37.2 million for the year ended December 31, 2006, versus $12.2 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 $5.9 million versus $5.7 million for the year ended December 31, 2005. Leasehold amortization was $4.8 million versus $2.8 million in 2005.

We recorded an impairment expense of $9.9 million in the year ended December 31, 2006, $8.4 million of which 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. We recorded this impairment expense in conjunction with the receipt of the independent engineer s final report on reserves as of that date.

G&A expense 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 No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 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 Share-Based Compensation Plans to our consolidated financial statements for additional information.

	Year Ended December 31,		
	2007	**2006**	**2005**
		(In thousands)	

Other Income (Expense):			
Interest expense	$ (11,870)	$ (7,845)	$ (2,359)
Gain (loss) on derivatives not qualifying for hedge accounting	(6,439)	38,128	(37,680)
Loss on early extinguishment of debt		(612)	
Income tax (expense) benefit	(3,034)	(5,120)	13,144
Average total borrowings	235,712	99,542	30,417
Weighted average interest rate	5.0%	7.5%	7.0%

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Other Income (Expense)

Year ended December 31, 2007 compared to December 31, 2006

Interest expense was $11.9 million for 2007, compared to $7.8 million for 2006, with the increase primarily attributable to a higher level of average borrowings in 2007. With the issuance of 3.25% convertible notes in December 2006, the weighted average interest rate fell to 5.0%, a significant reduction from the prior year s 7.5%.

Loss on derivatives not qualifying for hedge accounting was $6.4 million for 2007, compared to a gain of $38.1 million for 2006. The loss in 2007 includes an unrealized loss of $15.6 million for the change in fair value of our ineffective gas and oil hedges, and a realized gain of $9.5 million for the effect of settled derivatives. The loss also includes an unrealized loss of $0.5 million and a realized gain of $0.2 million on our interest rate swap. All of our oil and gas hedges were ineffective in 2007. Our natural gas hedges were ineffective 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 to justify treatment as cash flow hedges pursuant to SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities* (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 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 on continuing operations of $3.0 million for 2007 includes a write off of our December 31, 2006 net deferred tax asset of $9.7 million and a tax benefit of $6.1 million to offset the tax expense related to discontinued operations. We increased our valuation allowance and reduced our net deferred tax asset to zero during 2007 after considering all available positive and negative evidence related to the realization of our deferred tax asset. Income tax expense on continuing operations of $5.1 million in 2006, which was non-cash, represents 35.5% of the pre-tax income in 2006.

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

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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 a 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 on continuing operations of $5.1 million which was non-cash represents 35.5% of the pre-tax income in 2006. Income tax benefit of $13.1 million in 2005 represents 35% of pre-tax loss in 2005. 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.

Discontinued Operations

In March 2007, we sold our assets in South Louisiana to a private company. As a result, we restated our financial information to reflect discontinued operations in our Current Report on Form 8-K dated August 7, 2007. We have presented comparative data for our discontinued operations below:

	Year Ended December 31,		
Discontinued Operations	**2007**	**2006**	**2005**
		(In thousands)	
Net Production:			
Natural gas (MMcf)	533	2,501	2,451
Oil and condensate (MBbls)	89	368	370
Total (MMcfe)	1,064	4,710	4,674
Average Daily Net Production (Mcfe)	2,915	12,904	12,805
Gain (loss) on disposal, net of tax	$ 9,662	$	$
Income (loss) from discontinued operations, net of tax	1,807	(7,660)	6,960
Total income (loss), net of tax	$ 11,469	$ (7,660)	$ 6,960

Year ended December 31, 2007 compared to December 31, 2006

In conjunction with the sale of our South Louisiana assets in March 2007, we realized a gain (loss) on disposal, net of tax, of $9.7 million ($14.9 million) before tax. Income, net of tax on discontinued operations was $1.8 million for 2007 versus a loss of $7.7 million for 2006. This includes an impairment expense, before tax, of $0.4 million and $14.9 million for the years ended December 31, 2007 and 2006, respectively, on certain assets treated as held for sale. See Note 9 Discontinued Operations and Note 12 Acquisitions and Divestitures to our consolidated financial statements for further discussion of our discontinued operations.

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

Loss, net of tax on discontinued operations was $7.7 million for the year ended December 31, 2006 compared to income, net of tax on discontinued operations of $7.0 million for the year ended December 31, 2005, representing substantially all of our oil and gas properties sold or held for sale in South Louisiana.

Liquidity

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;

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constructing and installing new production infrastructure;

acquiring and maintaining our lease position, specifically in the Cotton Valley trend;

plugging and abandoning depleted or uneconomic wells.

Our capital budget for 2008 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, 2007. In addition to the contractual obligations presented in the table, our Consolidated Balance Sheet at December 31, 2007 reflected accrued interest on our Bank Debt of $0.4 million payable in the first quarter of 2008. See Note 4 Long-Term Debt and Note 10 Commitments and Contingencies to our consolidated financial statements for additional information.

Payment due by Period

	Note	Total	2008	2009	2010	2011	2012 and After
Contractual Obligations							
Long term debt (1)	4	$ 215,500	$	$	$ 40,500	$ 175,000	
Interest on 3-1/4% notes	4	22,278	5,688	5,688	5,688	5,214	
Office space leases	10	1,576	881	605	48	42	
Office equipment leases	10	259	213	24	13	7	2
Drilling contracts	10	57,065	44,008	12,118	939		
Transportation contracts	10	2,330	1,104	1,226			
Total contractual obligations		$ 299,008	$ 51,894	$ 19,661	$ 47,188	$ 180,263	$ 2

(1) The $175.0 million 3.25% 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 $6.2 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 and borrowings under our revolving bank credit facility and second lien term loan. In the future, we may also access public markets to issue additional debt and/or equity securities.

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At December 31, 2007, we had excess borrowing capacity of $123.5 million under our revolving bank credit facility. Our primary sources of cash during 2007 were from funds generated from operations, bank borrowings, proceeds received from the issuance of $175.0 million of 3.25% convertible senior notes in December 2006, and the sale of our South Louisiana properties in March 2007, and $123.8 million in net proceeds from the issuance of common stock in late 2007. Cash was used primarily to fund exploration and development expenditures. During 2007 we made aggregate cash payments of $10.0 million for interest. There were no payments made in 2007 for federal income taxes. The table below summarizes the sources of cash during 2007, 2006 and 2005:

Cash flow statement information:	Year Ended December 31, 2007	2006	Variance	Year Ended December 31, 2006	2005	Variance
			(In thousands)			
Net Cash:						
Provided by operating activities	$ 85,925	$ 65,133	$ 20,792	$ 65,133	$ 45,562	$ 19,571
Used in investing activities	(219,193)	(258,737)	39,544	(258,737)	(163,571)	(95,166)
Provided by financing activities	131,532	179,946	(48,414)	179,946	134,402	45,544
Increase (decrease) in cash and cash equivalents	$ (1,736)	$ (13,658)	$ 11,922	$ (13,658)	$ 16,393	$ (30,051)

At December 31, 2007, we had a working capital deficit of $54.0 million and long-term debt of $215.5 million. The working capital deficit was due to timing differences between the expenditure of funds and accruals resulting from drilling and completion activities as well as collecting certain payments in advance of production.

Cash Flows

Year ended December 31, 2007 compared to year ended December 31, 2006

Operating activities. Cash flow from operations is dependent upon production volumes generated from our development, exploration and acquisition activities, the price of oil and natural gas and costs incurred in our operations. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities was $85.9 million, an increase of $20.8 million or 32% from $65.1 million in 2006. A 49% increase in operating revenues resulting from a 44% increase in production volumes from continuing operations contributed to the increased cash flow in 2007. Operating cash flow amounts are net of changes in our current assets and current liabilities, which provided additional cash flow of $17.9 million and $4.9 million for the years ended December 31, 2007 and 2006, respectively, with $12.5 million of the increase in 2007 due to a year-end prepay transaction. In late 2007, one of our physical purchasers advanced $12.5 million for gas to be delivered under contract in the first quarter of 2008.

Investing activities. Net cash used in investing activities was $219.2 million for the year ended December 31, 2007, compared to $258.7 million for 2006. This includes $291.5 million in capital expenditures partially offset by $72.3 million in net proceeds from the sale of our South Louisiana assets. Of the $291.5 million, approximately $273.8 million was spent for drilling and completion activities and $14.3 million for facility installation activities in the Cotton Valley trend. We spent $211.0 million in 2006 for drilling, completion and facility installation activities.

Financing activities. Net cash provided by financing activities was $131.5 million in 2007 versus $179.9 million in 2006. The majority of our net financing cash flows came from the $123.8 million in proceeds from the issuance of common stock net of purchased capped call options, and

$14.0 million in net proceeds from bank borrowings.

Our senior credit facility includes certain financial covenants with which we were in compliance as of December 31, 2007. We do not anticipate a lack of borrowing capacity under our senior credit facility or second lien 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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Year ended December 31, 2006 compared to year ended December 31, 2005

Operating activities. Cash flow from operations is dependent upon production volumes generated from our development, exploration and acquisition activities, the price of oil and natural gas and costs incurred in our operations. Our cash flow from operations is also impacted by changes in working capital. Net cash provided by operating activities was $65.1 million, an increase of 43% from $45.6 million in 2005. As previously mentioned, the 112% increase in operating revenues due to higher production volumes from our continuing operations 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.

3.25% Convertible Senior Notes

In December 2006, we issued $175.0 million in 3.25% convertible senior notes. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes represent our senior unsecured obligations and 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 which is paid semi-annually on June 1 and December 1. Before 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:

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

- 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

In connection with the offering of our 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 our 3.25% convertible senior notes or the conversion of the notes to shares pursuant to the terms of the indenture governing the

3.25% convertible senior notes.

The 3,122,263 shares of common stock outstanding as of December 31, 2007, 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.

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Senior Credit Facility

On November 17, 2005, we amended our existing credit agreement and entered into an amended and restated senior credit agreement (as amended, the Senior Credit Facility) and a 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 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of the borrowing base, which was established at $170 million as of December 31, 2007. At that date we had $40.5 million in outstanding 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 the bank base rate plus 0.00% to 0.50%, or LIBOR plus 1.25% to 2.25%, 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 in effect at December 31, 2007 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 4.25 times EBITDAX for the trailing four quarters. (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings includes realized gains (losses) from derivatives not qualifying for hedge accounting, but excludes unrealized gains (losses) from derivatives not qualifying for hedge accounting.)

On August 7, 2007, we entered into the Sixth Amendment to our Senior Credit Facility which amended the last of the above financial covenants beginning with the quarter ending June 30, 2007 and ending with the quarter ending December 31, 2007. The financial covenant was set to return to a 3.5 times Debt to EBITDAX limitation for the trailing four quarters beginning with the quarter ending March 31, 2008 by the terms of the Sixth Amendment. As a result of the sale of our South Louisiana assets in the first quarter of 2007 (see Note 6 Discontinued Operations to our consolidated financial statements), a preliminary EBITDAX calculation for the trailing four quarters ending June 30, 2007 (which excluded all EBITDAX generated by the sold South Louisiana assets) indicated that we might not be in compliance with the ratio at the 3.5 times limitation. As a result, we requested, and the bank group approved, amending the ratio as discussed above for the purpose of clarifying the calculation of the covenant.

On September 25, 2007, we entered into the Seventh Amendment to our Senior Credit Facility. This amendment increased the borrowing base from $110 million to $170 million and increased the upper limit of the LIBOR plus rate from 2.0% to 2.25%. All the other material terms remained the same.

On November 30, 2007, we entered into an Eighth Amendment to our Senior Credit Facility. The amendment included the following provisions:

allows us to enter into a new Second Lien Term Loan of up to $100 million to mature on December 31, 2010;

permits us to use proceeds from our equity offering to purchase capped call options at a cost of up to $35 million;

amends certain negative covenants in the event we enter into a new Second Lien Term Loan facility;

As of December 31, 2007, we were in compliance with all of the financial covenants of our Senior Credit Facility.

On January 11, 2008, we entered into the Ninth Amendment to our Senior Credit Facility. The amendment included the following provisions:

restated certain defined terms to reflect that the new Second Lien Term Loan did not close by December 31, 2007;

and in the event we entered into the new Second Lien Term Loan,

- reduces the borrowing base to $150 million less 30% of the amount of the second lien term loan in excess of $50 million; and
- revised the debt to EBITDAX ratio to (i) exclude the 3.25% convertible senior notes from the calculation and (ii) set the ratio at a maximum of 3.0 to 1.0.

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. There are no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the term loan borrowing accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. The terms of the Second Lien Term Loan Agreement contain material financial covenants which include:

- an asset coverage ratio (defined as the present value of proved reserves discounted at 10% to total debt, excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0;
- a total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt to exclude the 3.25% convertible senior notes); and
- an EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

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.

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.

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 before 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.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility, and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of BSC and J.P. Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. One third of the options will expire over each of three separate multi-day settlement periods beginning approximately 18 months, 24 months and 30 months from the closing of the offering, respectively.

The capped call option transactions are expected to result in our receipt, on a net share, cashless basis of a certain number of shares of our common stock if the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for the relevant tranche is greater than the lower call strike price of the capped call option transactions. We refer to the amount by which the market value per share exceeds the lower call strike price as an in-the-money amount for the relevant tranche of the capped call option transaction. The in-the-money amount will never exceed the difference between the upper call strike price and the lower call strike price (i.e., it will be capped). The lower call strike price is $23.50, which corresponds to the price to the public in the equity offering and the upper call strike price is $32.90, which corresponds to 140% of the price to the public in the offering. Both lower and upper call strike prices are subject to customary anti-dilution and certain other adjustments. The number of shares of our common stock that we will receive from the option counterparties upon expiration of each tranche of the capped call option transactions will be equal to the in-the-money amount of that tranche divided by the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for that tranche. If the stock price is equal to the upper call strike price of $32.90 on each of the settlement dates, we will recoup up to 1.6 million shares.

The capped call option agreements are separate transactions entered into by us with the option counterparties and were not part of the terms of the offering of common stock.

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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 used by us. We cannot predict the types of reserve revisions that will be required in future periods.

Successful efforts accounting

We use the successful efforts method to account for exploration and development expenditures and to calculate DD&A. 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. In the third quarter of 2007, we increased our valuation allowance against our deferred tax assets by $14.8 million and recognized a non-cash writedown of our net deferred tax asset to zero. As of December 31, 2007, we have reported a net deferred tax asset of zero.

FASB Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes*, provides guidance on recognition and measurement of uncertainties in income taxes and is applicable for fiscal years beginning after December 15, 2006. We adopted FIN 48 in the first quarter of 2007. See Notes 1 and 6 to our consolidated financial statements.

Derivative Instruments

As discussed in Item 7A. Quantitative and Qualitative Disclosures About Market Risk, we periodically use 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 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 and field prices; (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, and (c) fixed price physical contracts, which are term contracts priced at the field level. The terms of our current hedge agreements are described in Note 8 Hedging Activities to our consolidated financial statements.

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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 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 use 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, 2007, the commodity hedges we use were in the form of:

(a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX quoted prices;

(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; and

(c) fixed price physical contracts, whereby we agree in advance with the purchasers of our physical gas volumes as to specific quantities to be delivered and specific prices to be received for gas deliveries at specific transfer points in the future.

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See Note 8 Hedging Activities to our consolidated financial statements for additional information. At February 29, 2008, we had the following commodity hedges in place (in millions):

Fixed Price Physical Contracts	Daily Volume	Total Volume	Average Price (1)	
Natural gas (MMBtu)				
1Q 2008	23,500	728,500	$8.03	
2Q 2008	28,500	2,593,500	$8.05	
3Q 2008	28,500	2,622,000	$8.05	
4Q 2008	28,500	2,317,000	$8.04	
Collars			**Floor/Cap**	
Natural gas (MMBtu)				
1Q 2008	10,000	310,000	$ 8.00	$ 10.20
2Q 2008	10,000	910,000	$ 8.00	$ 10.20
3Q 2008	10,000	920,000	$ 8.00	$ 10.20
4Q 2008	10,000	920,000	$ 8.00	$ 10.20
1Q 2009	10,000	900,000	$ 8.00	$ 9.30
2Q 2009	10,000	910,000	$ 8.00	$ 9.30
3Q 2009	10,000	920,000	$ 8.00	$ 9.30
4Q 2009	10,000	920,000	$ 8.00	$ 9.30
Swaps (NYMEX)			**Average Price**	
Natural gas (MMBtu)				
2Q 2008	5,000	455,000	$8.69	
3Q 2008	5,000	460,000	$8.69	
4Q 2008	5,000	155,000	$8.69	
1Q 2009	20,000	1,800,000	$8.83	
2Q 2009	20,000	1,820,000	$8.83	
3Q 2009	20,000	1,840,000	$8.83	
4Q 2009	20,000	1,840,000	$8.83	
Swaps (TexOk)			**Price (2)**	
Natural gas (MMBtu)				
1Q 2009	20,000	1,800,000	$7.87	
2Q 2009	20,000	1,820,000	$7.87	
3Q 2009	20,000	1,840,000	$7.87	
4Q 2009	20,000	1,840,000	$7.87	

(1) Normal sale at a fixed field delivery point, a comparable NYMEX average price of $8.28.

(2) The index price is based upon Natural Gas Pipeline of America, TexOk zone as published in the Inside FERC. The comparable index price based on NYMEX was approximately $8.25/Mmbtu.

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 2007. The fair value of the crude oil and natural gas hedging contracts (excluding those designated as normal sales) in place at December 31, 2007, resulted in a current asset of $2.3 million and a long-term liability of $2.4 million. Based on oil and gas pricing in effect at December 31, 2007, a hypothetical 10% increase in oil and gas prices would have resulted in a current derivative liability of $0.3 million while a hypothetical 10% decrease in oil and gas prices would have increased the current derivative asset to $4.8 million. A hypothetical 10% increase in oil and gas prices would have increased the long-term derivative liability to $8.1 million while a hypothetical 10% decrease in oil and gas prices would have resulted in a long-term derivative asset of $3.3 million.

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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, 2007, we had the following interest rate swaps in place with BNP (in millions):

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount
2/27/2007	2/26/2009	4.86%	$40.0

The fair value of the interest rate swap contracts in place at December 31, 2007, resulted in a current liability of $0.4 million. Based on interest rates at December 31, 2007, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the asset.

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 F-1.

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, 2007, 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, 2007, is set forth on page F-2 of this Annual Report on Form 10-K and is incorporated by reference herein.

KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2007, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

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 10, 2008, are as follows:

Name	Age	Position
Patrick E. Malloy, III	65	Chairman of the Board of Directors
Walter G. Gil Goodrich	49	Vice Chairman, Chief Executive Officer and Director
Robert C. Turnham, Jr.	50	President, Chief Operating Officer and Director
David R. Looney	51	Executive Vice President and Chief Financial Officer
Mark E. Ferchau	53	Executive Vice President
Henry Goodrich	77	Chairman Emeritus and Director
Josiah T. Austin	61	Director
John T. Callaghan	53	Director
Geraldine A. Ferraro	72	Director
Michael J. Perdue	53	Director
Arthur A. Seeligson	49	Director
Gene Washington	61	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-eight 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 Forcenergy Inc. Before 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.

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 Lucerino & Associates 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. 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. Before 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. Ms. Ferraro served as a Member of Congress for three terms before 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. Before assuming his present position in October 2006, Mr. Perdue was President and Chief Executive Officer of Community Bancorp Inc., from July 2003. Before Community Bancorp Inc. Mr. Perdue was Executive Vice President of Entrepreneurial Corporate Group and President of its subsidiary, Entrepreneurial Capital Corporation. From 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 has been primarily engaged in the management of his personal investments since 1995 and is the Managing Partner of Seeligson Oil Co. Ltd. He has served as one of our directors since August 1995.

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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 before 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.

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 2008 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, Compensation Committee and our Nominating and Corporate Governance 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 in our definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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 Transactions with Related Persons and Corporate Governance Our Board Board Size; Director Independence in our definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

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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 F-1.

(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 May 30, 2007 (Incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2007).
3.2	Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.2 of the Company s Form 8-K filed February 19, 2008).
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 (File No. 001-12719)).
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 (Incorporated by reference to Exhibit 4.11 of the Company s Annual Report on Form 10-K for the year ended December 31, 2006).

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4.12	Indenture, dated December 6, 2006, between Goodrich Petroleum Corporation and Wells Fargo Bank, National Association, as Trustee (Incorporated by reference to Exhibit 4.12 of the Company s Annual Report on Form 10-K for the year ended December 31, 2006).
10.1	Goodrich Petroleum Corporation 1995 Stock Option Plan (Incorporated by reference to Exhibit 10.21 to the Company s Registration Statement filed May 30, 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 (File No. 001-12719)).
10.3	Goodrich Petroleum Corporation 1997 Non-Employee Director Compensation Plan (Incorporated by reference to the Company s Proxy Statement filed April 27, 1998 (File No. 001-12719)).
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 (File No. 001-12719)).
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 (File No. 001-12719)).
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 filed on May 10, 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).

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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 10.1 of the Company s Form 8-K filed on December 4, 2006).
10.20	Fourth 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 with 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 (Incorporated by reference to Exhibit 10.5 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.26	First Amendment to Severance Agreement between the Company and Walter G. Goodrich, dated April 11, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on April 16, 2007).
10.27	First Amendment to Severance Agreement between the Company and Robert C. Turnham, Jr. dated April 11, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on April 16, 2007).
10.28	First Amendment to Severance Agreement between the Company and David R. Looney dated April 11, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on April 16, 2007).
10.29	First Amendment to Severance Agreement between the Company and Mark E. Ferchau dated April 11, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Form 8-K filed on April 16, 2007).
10.30	First Amendment to Severance Agreement between the Company and James B. Davis dated April 11, 2007 (Incorporated by reference to Exhibit 10.5 of the Company s Form 8-K filed on April 16, 2007).
10.31	Second Amendment to Severance Agreement between the Company and Robert C. Turnham, Jr. dated May 17, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on May 21, 2007).

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10.32	Second Amendment to Severance Agreement between the Company and David R. Looney dated May 17, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Form 8-K filed on May 21, 2007).
10.33	Second Amendment to Severance Agreement between the Company and Mark E. Ferchau dated May 17, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Form 8-K filed on May 21, 2007).
10.34	Second Amendment to Severance Agreement between the Company and James B. Davis dated May 17, 2007 (Incorporated by reference to Exhibit 10.5 of the Company s Form 8-K filed on May 21, 2007).
10.35	Second Amendment to Severance Agreement between the Company and Walter G. Goodrich dated May 17, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on May 23, 2007).
10.36	Fifth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of August 7, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on August 9, 2007).
10.37	Letter Agreement by and between James B. Davis and Goodrich Petroleum Corporation dated September 10, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 14, 2007).
10.38	Sixth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of September 17, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 21, 2007).
10.39	Seventh Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of September 25, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on September 28, 2007).
10.40	Amended and Restated Severance Agreement between the Company and Walter G. Goodrich dated November 5, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.41	Amended and Restated Severance Agreement between the Company and Robert C. Turnham, Jr. dated November 5, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.42	Amended and Restated Severance Agreement between the Company and David R. Looney dated November 5, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.43	Amended and Restated Severance Agreement between the Company and Mark E. Ferchau dated November 5, 2007 (Incorporated by reference to Exhibit 10.4 of the Company s Quarterly Report on Form 10-Q filed on November 8, 2007).
10.44	Eighth 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, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 3, 2007).
10.45	Capped Call Option Confirmation among Goodrich Petroleum Corporation and Bear, Stearns International Limited, dated December 4, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on December 10, 2007).

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10.46	Capped Call Option Confirmation among Goodrich Petroleum Corporation and JP Morgan Chase Bank, National Association, dated December 4, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on December 10, 2007).
10.47	Ninth Amendment to Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of January 11, 2008 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K filed on January 17, 2008).
10.48	Second Lien Term Loan Agreement among Goodrich Petroleum Company, L.L.C. and BNP Paribas and Certain Lenders, dated as of January 16, 2008 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K filed on January 17, 2008).
*10.49	Non-employee Director Compensation Summary.
*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 the State of Louisiana.
	Goodrich Petroleum Company-Lafitte, LLC-organized in the State of Louisiana.
	Drilling & Work over Company, Inc.-incorporated in the 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:

Bbls	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 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.

PV-10 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

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economic and operating conditions. Reservoirs are considered proved if shown to be economically producible by either actual production or conclusive formation tests.

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, 2008.

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

/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 **Michael J. Perdue**	Director
/s/ Arthur A. Seeligson **Arthur A. Seeligson**	Director
/s/ Gene Washington **Gene Washington**	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, 2007. The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included on page F-4.

Management of Goodrich Petroleum Corporation

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, 2007 and 2006, 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, 2007. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, 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), Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2007, 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 13, 2008 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

KPMG LLP

Houston, Texas

March 13, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Goodrich Petroleum Corporation:

We have audited Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2007, 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, included in the accompanying Management s Annual Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Goodrich Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2007 and 2006, 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, 2007, and our report dated March 13, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas

March 13, 2008

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(In Thousands, Except Share Amounts)

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,448	$ 6,184
Accounts receivable, trade and other, net of allowance	8,539	9,665
Accrued oil and gas revenue	12,200	10,689
Fair value of oil and gas derivatives	2,267	13,419
Fair value of interest rate derivatives		219
Assets held for sale	311	
Prepaid expenses and other	904	994
Total current assets	28,669	41,170
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	723,239	575,666
Furniture, fixtures and equipment	1,932	1,463
	725,171	577,129
Less: Accumulated depletion, depreciation and amortization	(168,523)	(156,509)
Net property and equipment	556,648	420,620
OTHER ASSETS:		
Restricted cash and investments		2,039
Deferred tax asset		9,705
Other	4,801	5,730
Total other assets	4,801	17,474
TOTAL ASSETS	$ 590,118	$ 479,264
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 36,967	$ 36,263
Accrued liabilities	32,565	26,811
Fair value of interest rate derivatives	384	
Deferred revenue	12,500	
Accrued abandonment costs	312	263
Total current liabilities	82,728	63,337
LONG-TERM DEBT	215,500	201,500
Accrued abandonment costs	5,868	9,294
Fair value of oil and gas derivatives	2,407	

Total liabilities	306,503	274,131
Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000	2,250	2,250
Common stock: $0.20 par value, 100,000,000 and 50,000,000 shares authorized, respectively; issued and outstanding 34,821,317 and 28,218,422 shares, respectively	6,340	5,049
Treasury stock (shares outstanding 16,359)	(422)	
Additional paid in capital	341,098	213,666
Accumulated deficit	(65,651)	(14,571)
Accumulated other comprehensive loss		(1,261)
Total stockholders equity	283,615	205,133
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 590,118	$ 479,264

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, 2007	2006	2005
REVENUES:			
Oil and gas revenues	$ 110,691	$ 73,933	$ 34,986
Other	614	838	325
	111,305	74,771	35,311
OPERATING EXPENSES:			
Lease Operating expense	22,465	12,688	3,494
Production and other taxes	2,272	3,345	2,136
Transportation	5,964	3,791	558
Depreciation, depletion and amortization	79,766	37,225	12,214
Exploration	7,346	5,888	5,697
Impairment of oil and gas properties	7,696	9,886	340
General and administrative	20,888	17,223	8,622
Gain on sale of assets	(42)	(23)	(235)
Other	109		
	146,464	90,023	32,826
Operating income (loss)	(35,159)	(15,252)	2,485
OTHER INCOME AND (EXPENSE)			
Interest expense	(11,870)	(7,845)	(2,359)
Gain (loss) on derivatives not qualifying for hedge accounting	(6,439)	38,128	(37,680)
Loss on early extinguishment of debt		(612)	
	(18,309)	29,671	(40,039)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(53,468)	14,419	(37,554)
INCOME TAX (EXPENSE) BENEFIT	(3,034)	(5,120)	13,144
INCOME (LOSS) FROM CONTINUING OPERATIONS	(56,502)	9,299	(24,410)
DISCONTINUED OPERATIONS			
Gain on sale of assets, net of tax (See Note 12)	9,662		
Income (loss) on discontinued operations, net of tax (See Note 9)	1,807	(7,660)	6,960
	11,469	(7,660)	6,960
NET INCOME (LOSS)	(45,033)	1,639	(17,450)
PREFERRED STOCK DIVIDENDS	6,047	6,016	755
PREFERRED STOCK REDEMPTION PREMIUM		1,545	

NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (51,080)	$ (5,922)	$ (18,205)
NET INCOME (LOSS) PER COMMON SHARE BASIC			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ (2.21)	$ 0.37	$ (1.05)
DISCONTINUED OPERATIONS	$ 0.45	$ (0.30)	$ 0.30
NET INCOME (LOSS)	$ (1.76)	$ 0.07	$ (0.75)
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (2.00)	$ (0.24)	$ (0.78)
NET INCOME (LOSS) PER COMMON SHARE DILUTED			
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ (2.21)	$ 0.37	$ (1.05)
DISCONTINUED OPERATIONS	$ 0.45	$ (0.31)	$ 0.30
NET INCOME (LOSS)	$ (1.76)	$ 0.06	$ (0.75)
NET INCOME (LOSS) APPLICABLE TO COMMON STOCK	$ (2.00)	$ (0.24)	$ (0.78)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING BASIC	25,578	24,948	23,333
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING DILUTED	25,578	25,412	23,333

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, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ (45,033)	$ 1,639	$ (17,450)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	79,766	52,642	25,563
Unrealized (gain) loss on derivatives not qualifying for hedge accounting	16,079	(40,185)	26,960
Deferred income taxes	9,025	904	(9,396)
Dry hole costs	939	7,926	2,014
Amortization of leasehold costs	6,211	5,488	3,344
Impairment of oil and gas properties	9,223	24,790	340
Stock based compensation (non-cash)	5,282	5,962	1,383
Loss on early extinguishment of debt		612	
Gain on sale of assets	(14,792)	(23)	(235)
Other non-cash items	1,370	476	(156)
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	1,105	(3,268)	786
Deferred revenue	12,500		
Accrued oil and gas revenue	(1,511)	1,174	(8,741)
Prepaid expenses and other	330	(531)	169
Accounts payable	5,022	4,689	8,222
Accrued liabilities	409	2,838	12,759
Net cash provided by operating activities	85,925	65,133	45,562
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(291,486)	(261,435)	(164,551)
Proceeds from sale of assets	72,293	2,698	980
Net cash used in investing activities	(219,193)	(258,737)	(163,571)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(173,000)	(184,500)	(118,500)
Proceeds from bank borrowings	187,000	181,000	121,500
Proceeds from convertible note offering		175,000	
Net proceeds from common stock offering	123,815		53,112
Net proceeds from preferred stock offering		28,973	79,775
Redemption of preferred stock		(9,319)	
Exercise of stock options and warrants	203	406	477
Production payments			(297)
Deferred financing costs	(439)	(5,598)	(971)
Preferred stock dividends	(6,047)	(6,016)	(634)
Other			(60)
Net cash provided by financing activities	131,532	179,946	134,402

INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,736)	(13,658)	16,393
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	6,184	19,842	3,449
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 4,448	$ 6,184	$ 19,842
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
CASH PAID DURING THE YEAR FOR INTEREST	$ 10,178	$ 7,284	$ 1,862
CASH PAID DURING THE YEAR FOR INCOME TAXES	$	$	$ 110

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In Thousands)

	2007		2006		2005	
	Shares	Amount	Shares	Amount	Shares	Amount
Series A Preferred Stock						
Balance, beginning of year		$	792	$ 792	792	$ 792
Offering of preferred stock			(792)	(792)		
Balance, end of year		$		$	792	$ 792
Series B Preferred Stock						
Balance, beginning of year	2,250	$ 2,250	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	2,250	$ 2,250	1,650	$ 1,650
Common stock						
Balance, beginning of year	28,218	$ 5,049	24,805	$ 4,961	20,587	$ 4,117
Offering of common stock	6,431	1,286			3,710	742
Redemption of Series A preferred stock			6	1		
Issuance of and amortization of restricted stock	108	(8)	182	36	123	25
Exercise of stock options and warrants	57	12	66	44	371	74
Director stock grants	7	1	37	7	14	3
Shares pursuant to share lending agreement			3,122			
Balance, end of year	34,821	$ 6,340	28,218	$ 5,049	24,805	$ 4,961
Treasury Stock						
Balance, beginning of year		$		$		$
Purchases	40	(1,231)				
Retirements	(24)	809				
Balance, end of year	16	$ (422)		$		$
Paid in Capital						
Balance, beginning of year		$ 213,666		$ 187,967		$ 55,409
Offering of common stock		122,529				52,370
Offering of preferred stock				28,373		78,125
Redemption of Series A preferred stock				(6,983)		
Issuance of and amortization of restricted stock		1,745		2,205		1,423
Reclassification from unamortized restricted stock upon adoption of FAS 123R				(2,066)		
Stock based compensation		2,727		2,487		
Exercise of stock options and warrants		192		295		403
Director stock grants		239		1,388		237
Balance, end of year		$ 341,098		$ 213,666		$ 187,967
Retained Earnings (Deficit)						
Balance, beginning of year		(14,571)		(8,649)		9,556

Net income (loss)	(45,033)	1,639	(17,450)
Redemption of Series A preferred stock		(1,545)	
Preferred stock dividend	(6,047)	(6,016)	(755)
Balance, end of year	$ (65,651)	$ (14,571)	$ (8,649)
Unamortized Restricted Stock Awards			
Balance, beginning of year	$	$ (2,066)	(1,762)
Issuance of and amortization of restricted stock			(304)
Reclassification to APIC upon adoption of FAS 123R		2,066	
Balance, end of year	$	$	$ (2,066)
Accumulated Other Comprehensive Loss			
Balance, beginning of year	$ (1,261)	$ (3,066)	$ (2,805)
Other comprehensive loss	1,261	1,805	(261)
Balance, end of year	$	$ (1,261)	$ (3,066)
Total Stockholder s Equity at December 31	$ 283,615	$ 205,133	$ 181,589

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,		
	2007	**2006**	**2005**
Net Income (loss)	$ (45,033)	$ 1,639	$ (17,450)
Other comprehensive income (loss):			
Change in fair value of derivatives (1)		(1,025)	(6,233)
Reclassification adjustment (2)	1,261	2,830	5,972
Other comprehensive income (loss)	1,261	1,805	(261)
Comprehensive income (loss)	$ (43,772)	$ 3,444	$ (17,711)
(1) Net of Income tax benefit of:	$	$ 552	$ 3,356
(2) Net of income tax expense of:	$ 679	$ 1,524	$ 3,216

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, 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.

Presentation Change The Consolidated Statement of Operations includes a category of expense titled Production and other taxes which is a change from Production taxes in prior period presentations. The changed category includes ad valorem taxes as well as production taxes for which all comparative periods presented have been adjusted.

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.

Assets Held for Sale Assets Held for Sale as of December 31, 2007, represent our remaining assets in South Louisiana. These assets include the St. Gabriel, Bayou Bouillon and Plumb Bob fields.

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, 2007, 2006 and 2005, we recorded impairments on continuing operations of $7.7 million, $9.9 million and $0.3 million, respectively, as a result of certain non-core fields depleting earlier than anticipated.

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

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.

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, 2007, 2006 and 2005, the net assets for gas balancing were $1.2 million, $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.

Derivative Instruments and Hedging Activities We use 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. 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.

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Income Taxes We follow the provisions of SFAS No. 109, *Accounting for Income Taxes*, (SFAS 109) as clarified by FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), 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. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

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 calculated using the Treasury Stock method.

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 three purchasers accounted for 31%, 23% and 10% of oil and gas revenues for the year ended December 31, 2007. 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.

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.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 June, 2006 the FASB issued FIN 48 which requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. We adopted the provisions of FIN 48 on January 1, 2007. There was no cumulative effect adjustment to retained earnings, our financial condition or results of operations as a result of implementing FIN 48. The amount of unrecognized tax benefits did not materially change as of December 31, 2007. See Note 6.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS 157), which establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop these assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. SFAS 157 is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007 and interim period within those fiscal years. For non-financial assets and liabilities, the adoption of SFAS 157 has been deferred until January 1, 2009. We are adopting SFAS 157 as of January 1, 2008. We are currently in the process of determining the effects of adoption, such as the effect of incorporating our own credit standing in the measurement of certain liabilities. We do not expect that the final effects of adoption will have a significant impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. We adopted SFAS 159 as of January 1, 2008. Adoption had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

In April 2007, the FASB issued FSP FIN 39-1*, An Amendment of FASB Interpretation No. 39* (FSP FIN 39-1). FSP FIN 39-1 allows companies to offset fair value amounts recognized for derivative instruments and the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master netting arrangement. A company must make an accounting policy decision whether or not to offset fair value amounts. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007 and is to be applied retrospectively. We are currently evaluating the provisions of FSP FIN 39-1 and assessing the impact it may have on our financial position and results of operations.

In December 2007, the FASB issued SFAS 141(R), *Business Combinations* (SFAS 141(R)) and SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements* (SFAS 160). These statements require most identifiable assets, liabilities and noncontrolling interests to be recorded at full fair value and require noncontrolling interests to be reported as a component of equity. Both statements are effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. SFAS 141(R) will be applied to business combinations occurring after the effective date and SFAS 160 will be applied prospectively to all

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

noncontrolling interests, including any that arose before the effective date. We are currently evaluating the provisions of SFAS 141(R) and SFAS 160 and assessing the impact, if any, they may have on our financial position and results of operations.

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 Share-Based Compensation Plans

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan replaces our previously adopted Goodrich Petroleum Corporation 1995 Stock Option Plan and 1997 Non-Employee Directors Stock Option Plan.

The 2006 Plan is intended to promote the interests of the Company, by providing a means by which Employees, Consultants and Directors may acquire or increase their equity interest in the Company and may develop a sense of proprietorship and personal involvement in the development and financial success of the Company, and to encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its stockholders. The Plan is also contemplated to enhance the ability of the Company and its Subsidiaries to attract and retain the services of individuals who are essential for the growth and profitability of the Company.

The 2006 Plan provides that the Compensation Committee shall have the authority to determine the Participants to whom stock options, restricted stock, performance awards, phantom shares and Stock Appreciation Rights may be granted. The 2006 Plan also provides for grants to non-employee directors. The 2006 Plan provides that the option price of shares issued be equal to the market price on the date of grant. With the exception of option grants to non-employee directors which vest immediately, options vest ratably on the anniversary of the date of grant over a period of time, typically three years. All options expire ten years after the date of grant.

Restricted (phantom) shares awarded under the 2006 Plan typically have a restriction period of three years. During the restriction period, ownership of the shares cannot be transferred and the shares are subject to forfeiture if employment ends before the end of the restriction period. Certain restricted stock awards provide for accelerated vesting. Restricted (phantom) shares are not considered to be currently issued and outstanding. The fair value of the awards of restricted (phantom) shares, determined as the market value of the shares at the date of grant, is expensed ratably over the restricted period.

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.

As of December 31, 2007, a total of 1,792,278 shares were available for future grants under the 2006 Stock Plan.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of stock option activity is as follows:

	2007		2006		2005	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,023,500	$ 20.01	519,500	$ 13.70	410,500	$ 10.48
Granted			625,000	24.10	150,000	19.78
Exercised	(57,500)	3.54	(66,000)	7.23	(41,000)	3.68
Forfeited	(16,667)	23.39	(55,000)	22.13		
Outstanding at end of year	949,333	$ 20.95	1,023,500	$ 20.01	519,500	$ 13.70
Exercisable at end of year	643,433	$ 19.33	492,167	$ 16.36	372,100	$ 12.60
Weighted average fair value of stock options granted		N/A		$ 12.98		$ 9.69

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2007	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2007	Weighted Average Exercise Price
$2.63 to $5.85	46,000	2.97	$ 3.83	46,000	$ 3.83
$16.46 & $19.78	340,000	7.10	17.92	340,000	17.92
$23.39 & $27.81	563,333	8.01	24.17	257,334	23.96
	949,333	7.44	$ 20.95	643,334	$ 19.33

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, 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 2007, 2006 and 2005, we contributed $0.4 million, $7.1 million and $1.5 million, respectively, under the plan through the issuance of 13,000, 215,629 and 75,750 shares, respectively, of our common stock. During 2007, 2006 and 2005, $2.6 million, $2.1 million and $1.1 million, respectively, were charged to compensation expense related to the restricted share awards. During 2007, 2006 and 2005, we recorded credits to the equity account of $1.0 million, $0.4 million and $0.1 million, respectively, for the value of 35,541, 18,162 and 12,832, respectively, of non-vested restricted share awards that were forfeited by employees. The fair value of restricted stock vested during 2007, 2006, and 2005 were $4.5 million, $1.4 million and $0.8 million, respectively.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Total stock based compensation for the year ended December 31, 2007, of $5.3 million has been recognized as a component of general and administrative expenses in the accompanying Consolidated Financial Statements.

Before 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. Before 2006, we provided pro forma disclosure amounts in accordance with SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, 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.

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

	2005
Net loss as reported	$ (17,450)
Add: Stock based compensation programs recorded as expense, net of tax	743
Deduct: Total stock compensation expense, net of tax	(1,236)
Pro forma net loss	$ (17,943)
Net loss applicable to common stock, as reported	$ (18,205)
Add: Stock based compensation programs recorded as expense, net of tax	743
Deduct: Total stock compensation expense, net of tax	(1,236)
Pro forma net loss applicable to common stock	$ (18,698)
Net loss applicable to common stock per share:	
Basic as reported	$ (0.78)
Basic pro forma	$ (0.80)
Diluted as reported	$ (0.78)
Diluted pro forma	$ (0.80)

The per share weighted average fair value of stock options granted during the years ended December 31, 2006 and 2005, were $12.98 and $9.69, 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). There were no options granted in the 2007 calendar year. The following schedule reflects the various assumptions included in this model as it relates to the valuation of our options:

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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,		
	2007	2006	2005
Restricted stock:			
Pretax compensation expense	$ 2,555	$ 2,092	$ 1,143
Tax benefit		(732)	(400)
Restricted stock expense, net of tax	$ 2,555	$ 1,360	$ 743
Director stock grants:			
Pretax compensation expense	$ 252	$ 1,383	$ 240
Tax benefit		(484)	(84)
Director stock grants expense, net of tax	$ 252	$ 899	$ 156
Stock options:			
Pretax compensation expense	$ 2,727	$ 2,487	$
Tax benefit		(870)	
Stock option expense, net of tax	$ 2,727	$ 1,617	$
Total share based compensation:			
Pretax compensation expense	$ 5,534	$ 5,962	$ 1,383
Tax benefit		(2,086)	(484)
Total share based compensation expense, net of tax	$ 5,534	$ 3,876	$ 899

As of December 31, 2007, $3.5 million and $4.1 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 1.6 years for restricted stock and 2.1 years for stock options.

Option activity under our stock option plans as of December 31, 2007, and changes during the 12 months then ended were as follows:

	Shares	Wtd. Avg. Exercise Price	Remaining Contractual Term	Aggregate Intrinsic Value
		(in thousands)		
Outstanding at January 1, 2007	1,023,500	$ 20.01		
Granted				
Exercised	(57,500)	3.54		$ 1,784
Forfeited	(16,667)	23.39		
Outstanding at December 31, 2007	949,333	$ 20.95	7.44	$ 1,585
Exercisable at December 31, 2007	643,334	$ 19.33	7.16	$ 2,115

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2007 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, 2007. 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, 2007, 2006, and 2005 was $1.8 million, $1.7 million and $0.8 million, respectively.

The following table summarizes information on unvested restricted stock outstanding as of December 31, 2007:

	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
Unvested at January 1, 2007	279,054	$ 26.54	$ 7,407,267
Vested	(148,262)	21.33	(3,162,578)
Granted	13,000	33.10	430,235
Forfeited	(35,541)	29.19	(1,037,416)
Unvested at December 31, 2007	108,251	$ 33.60	$ 3,637,508

In May 2006, an officer of the company resigned and we 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 before 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 we 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. In August 2007, an officer of the Company resigned for which we accelerated vesting of 16,667 shares of options and 7,800 shares of restricted shares recognizing $0.3 million in compensation expense.

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.

In August of 2007, an officer of the Company resigned and the Company accelerated the vesting of (1) options to purchase 16,667 shares granted at $23.39 per share in December 2005 and (2) 7,800 shares of previously unvested restricted stock. 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 $0.3 million.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 3 Asset Retirement Obligations

The Company follows SFAS No. 143 which requires the Company to record the fair value of a liability associated with the retirement obligations of its tangible long-lived assets in the periods in which it is incurred. The Company capitalizes the discounted fair value of the liability when initially incurred. The liability is accreted through accretion expense to its full fair value during the life of the long-lived asset.

The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2007, 2006 and 2005, is as follows (in thousands):

	December 31,		
	2007	2006	2005
Beginning balance	$ 9,557	$ 7,960	$ 6,811
Liabilities incurred	2,710	1,366	1,004
Liabilities settled	(41)	(190)	(39)
Accretion expenses (reflected in depletion, depreciation and amortization expense)	221	438	363
Dispositions and other	(6,267)	(17)	(179)
Ending balance	$ 6,180	$ 9,557	$ 7,960
Current liability	$ 312	$ 263	$ 92
Long term liability	$ 5,868	$ 9,294	$ 7,868

Dispositions and other for 2007 represents the Asset Retirement Obligation for substantially all of our properties in South Louisiana sold to a private company. The ending balance at December 31, 2007, includes $0.3 million for Assets Held for Sale. See Note 9.

NOTE 4 Long-Term Debt

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

	December 31,	
	2007	2006
Senior Credit Facility	$ 40,500	$ 26,500
Convertible 3.25% Senior Notes due 2026	175,000	175,000
Total Long-term debt	$ 215,500	$ 201,500

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 represent our senior unsecured obligations and 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 which is paid semi-annually on June 1 and December 1.

Before 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:

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

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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 (as amended, the Senior Credit Facility) and a 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 million which matures on February 25, 2010. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of the borrowing base, which was established at $170 million as of December 31, 2007. At that date we had $40.5 million in outstanding 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 2.25%, 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 in effect at December 31, 2007 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 4.25 times EBITDAX for the trailing four quarters. (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings includes realized gains (losses) from derivatives not qualifying for hedge accounting, but excludes unrealized gains (losses) from derivatives not qualifying for hedge accounting.)

On August 7, 2007, we entered into the Sixth Amendment to our Senior Credit Facility, which amended the last of the above financial covenants beginning with the quarter ending June 30, 2007 and ending with the quarter ending December 31, 2007. The financial covenant was set to return to a 3.5 times Debt to EBITDAX limitation for the trailing four quarters beginning with the quarter ending March 31, 2008 by the terms of the Sixth Amendment. As a result of the sale of our South Louisiana assets in the first quarter of 2007 (see Note 6 Discontinued Operations to our consolidated financial statements), a preliminary EBITDAX calculation for the trailing four quarters ending June 30, 2007 (which excluded all EBITDAX generated by the sold South Louisiana assets) indicated that we might not be in compliance with the ratio at the 3.5 times limitation. As a result, we requested, and the bank group approved, amending the ratio as discussed above for the purpose of clarifying the calculation of the covenant.

On September 25, 2007, we entered into the Seventh Amendment to our Senior Credit Facility. This amendment increased the borrowing base from $110 million to $170 million and increased the upper limit of the LIBOR plus rate from 2.0% to 2.25%. All the other material terms remained the same.

On November 30, 2007, we entered into the Eighth Amendment to our Senior Credit Facility. The amendment includes the following provisions:

- allows us to enter into a new Second Lien Term Loan of up to $100 million to mature on December 31, 2010;

- permits us to use proceeds from our equity offering to purchase capped call options at a cost of up to $35 million;

- amends certain negative covenants in the event we entered into a new Second Lien Term Loan facility;

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2007, we were in compliance with all of the financial covenants of our Senior Credit Facility.

On January 11, 2008, we entered into the Ninth Amendment to our Senior Credit Facility. The amendment includes the following provisions:

- restates certain defined terms to reflect that the new Second Lien Term Loan did not close by December 31, 2007;
- and in the event we entered into the new Second Lien Term Loan,
  - reduces the borrowing base to $150 million less 30% of the amount of the Second Lien Term Loan in excess of $50 million; and
  - revised the debt to EBITDAX ratio to (i) exclude the 3.25% convertible senior notes from the calculation and (ii) set the ratio at a maximum of 3.0 to 1.0.

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. There are no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the term loan borrowing accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. The terms of the Second Lien Term Loan Agreement contain material financial covenants which include:

- an asset coverage ratio (defined as the present value of proved reserves discounted 10% to total debt, excludes 3.25% convertible notes) of not less than 1.5 to 1.0;
- a total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt to exclude the 3.25% convertible senior notes); and
- an EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

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, 2007, 2006 and 2005. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Basic method	25,578	24,948	23,333
Stock warrants		129	
Stock options and restricted stock		335	
Dilutive method	25,578	25,412	23,333

Common shares on assumed conversion of restricted and employee option stock for the year ended December 31, 2007 in the amount of 210,180 shares were not included in the computation of diluted loss per common share since they would be anti-dilutive.

NOTE 6 Income Taxes

Uncertain Tax Positions

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations as a result of implementing FIN 48. The amount of unrecognized tax benefits did not

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

materially change as of December 31, 2007. The amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on the results of operations or the financial position of the Company. The Company files a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions. With limited exceptions, the Company is no longer subject to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1992.

The Company s continuing practice is to recognize estimated interest and penalties related to potential underpayment on any unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations. As of the date of adoption of FIN 48, Goodrich did not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense recognized during the quarter. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations before December 31, 2008.

The Company accounts for income taxes in accordance with SFAS No. 109, as clarified by FIN 48 which requires the Company to recognize income tax benefits for loss carry forwards that have not previously been recorded. The tax benefits recognized must be reduced by a valuation allowance when it is more likely than not that the deferred tax asset will not be realized. During 2007, the Company eliminated its net deferred tax asset and increased its valuation allowance by $19.7 million.

In determining the carrying value of a deferred tax asset, SFAS 109 provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. As we have incurred net operating losses in 2006 and prior years, relevant accounting guidance suggests that cumulative losses in recent years constitute significant negative evidence, and that future expectations about income are insufficient to overcome a history of such losses. We increased our valuation allowance and reduced our net deferred tax asset to zero during 2007 after considering all available positive and negative evidence related to the realization of our deferred tax asset. If we achieve profitable operations in the future, we may reverse a portion of the valuation allowance in an amount at least sufficient to eliminate any tax provision in that period. The valuation allowance has no impact on our net operating loss (NOL) position for tax purposes, and if we generate taxable income in future periods, we will be able to use our NOLs to offset taxes due at that time. The Company will continue to assess the valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. The Company s NOL position at year end 2007 stood at approximately $62.7 million.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Current:			
Federal	$ (97)	$	$
State			
	(97)		

Deferred:			
Federal	(9,025)	(904)	9,397
State			
	(9,025)	(904)	9,397
Total	$ (9,122)	$ (904)	$ 9,397

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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,		
	2007	**2006**	**2005**
Income (loss) from continuing operations			
Tax at U.S. statutory income tax	$ 18,713	$ (5,106)	$ 13,144
Nondeductible expenses	(59)	(14)	(5)
Valuation allowance and other	(21,688)		5
	(3,034)	(5,120)	13,144
Income (loss) from discontinued operations			
Tax at U.S. statutory income tax	(6,088)	4,216	(3,747)
	(6,088)	4,216	(3,747)
Total tax (expense) benefit	$ (9,122)	$ (904)	$ 9,397

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2007 and 2006 are presented below (in thousands).

	2007	**2006**
Deferred tax assets:		
Differences between book and tax basis of:		
Operating loss carryforwards	$ 18,725	$ 24,599
Statutory depletion carryforward	7,034	7,034
AMT tax credit carryforward	1,523	1,480
Derivative financial instruments	184	
Compensation	2,075	421
Contingent liabilities and other	4,906	462
Total gross deferred tax assets	34,447	33,996
Less valuation allowance	(32,961)	(13,263)
Net deferred tax asset	1,486	20,733
Deferred tax liabilities:		
Differences between book and tax basis of:		
Property and equipment	(126)	(6,255)
Bond discount	(1,360)	
Derivative financial instruments		(4,773)

Total gross deferred tax liabilities	(1,486)	(11,028)
Net deferred tax asset		9,705

Our stock based deferred compensation plans generated $5.7 million of additional tax deductions in 2007 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.