GOODRICH PETROLEUM CORP
Form 10-K
February 22, 2011

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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, 2010

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	**76-0466193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
801 Louisiana, Suite 700 Houston, Texas	**77002**
(Address of principal executive offices)	**(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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, 2010) the last business day of the registrant s most recently completed second fiscal quarter was approximately $319 million. The number of shares of the registrant s common stock outstanding as of February 14, 2011 was 37,672,853.

Documents Incorporated By Reference:

Portions of Goodrich Petroleum Corporation s definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2010, 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, 2010

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PART I

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

General

Goodrich Petroleum Corporation (together with its subsidiary, we, our, or the Company) is an independent oil and gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in Northwest Louisiana, East Texas and South Texas. The geological formations we target are the Haynesville Shale and Cotton Valley Taylor sand in Northwest Louisiana and East Texas and the Eagle Ford Shale in South Texas. In the current natural gas price environment we are concentrating a majority of our development efforts on existing leased acreage with formations that are prospective for oil. In addition, we continue to aggressively pursue the evaluation and acquisition of prospective acreage and oil and gas drilling opportunities outside of our existing leased acreage. We own working interests in 382 producing oil and gas wells located in 32 fields in 7 states. At December 31, 2010, we had estimated proved reserves of approximately 454.2 Bcf of natural gas and 1.6 MMBbls of oil and condensate.

We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise and related information.

Available Information

Our principal executive offices are located at 801 Louisiana Street, Suite 700, Houston, Texas 77002.

Our website address is *http://www.goodrichpetroleum.com.* We make available, free of charge through the Investor Relations portion of our 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 Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (SEC). Reports of beneficial ownership filed pursuant to Section 16(a) of the Exchange Act are also available on our website. Information contained on our website is not part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

Oil and Gas Operations and Properties

Overview. As of December 31, 2010, nearly all of our proved oil and gas reserves were located in Northwest Louisiana, East Texas and South Texas. We spent nearly all of our 2010 capital expenditures of $283.7 million in these areas, with $175.1 million or 62% spent on the Haynesville Shale trend and $72.9 million or 26% spent on the Eagle Ford Shale trend. Our total capital expenditures, including accrued costs for services performed during 2010, consist of $247.5 million for drilling and completion costs, $33.6 million for leasehold acquisition, $0.6 million for facilities and infrastructure, $1.2 million for geological and geophysical costs and $0.8 million for furniture, fixtures and equipment.

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Eagle Ford Shale Trend

During 2010, we acquired or farmed-in leases totaling approximately 67,036 gross (37,794 net) lease acres and began development and production activity in the Eagle Ford Shale trend in La Salle and Frio Counties located in South Texas. During 2010, we drilled and completed 6 gross (4.1 net) oil wells all of which were successful.

Haynesville Shale Trend

As of December 31, 2010, we have acquired or farmed-in leases totaling approximately 158,749 gross (88,722 net) acres and are continually attempting to acquire additional acreage prospective for the Haynesville Shale. During 2010, we drilled and completed 36 gross Haynesville Shale wells with a 100% success rate. Our Haynesville Shale drilling activities are located in five primary leasehold areas in East Texas and Northwest Louisiana.

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In those fields or areas where we have made the determination that it is prospective for the Haynesville Shale, the table below details our acreage positions, average working interest and wells drilled and completed in the Haynesville Shale.

Field or Area	Haynesville Acreage As of December 31, 2010 Gross	Net	Average Working Interest	Wells Drilled and Completed As of December 31, 2010 Successful	Unsuccessful
North Minden	31,506	25,890	100%	6	
Beckville	14,925	11,081	100%	6	
Shelby Trough/Angelina River	48,386	27,374	66%	2	
Bethany Longstreet	25,124	11,956	35%	50	
Greenwood Waskom/Metcalf	4,978	3,796	58%	6	
Other	33,830	8,625	47%	15	
Total Haynesville Shale Trend	158,749	88,722	49%	85	

In December, 2010, we sold a significant amount of our shallow rights in several fields in East Texas and Northwest Louisiana, but retained ownership of all the deep rights including the Haynesville and Bossier Shale formations. The sale resulted in net proceeds of $65.2 million, after normal closing adjustments.

As of December 31, 2010, we maintain ownership interests in acreage and/or wells in several additional fields including: the Midway field in San Patricio County, Texas and the Garfield Unit in Kalkaska County, Michigan.

See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations in this report for additional information on our recent operations in the Haynesville Shale and Eagle Ford Shale trends.

Oil and Natural Gas Reserves

In December 2008, the SEC adopted new rules related to modernizing reserves definitions and disclosure requirements for oil and natural gas companies, which became effective prospectively for annual reporting periods ending on or after December 31, 2009. The new rules expand the definition of oil and gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of proved reserves, which was revised to indicate that entities must use the average of beginning-of-the-month commodity prices over the preceding 12-month period, rather than the end-of-period price, when estimating whether reserve quantities are economical to produce. Likewise, the 12-month average price is now used to estimate reserves utilized to compute depreciation, depletion and amortization. Another significant provision of the new rules is a requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of initial booking.

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The following tables set forth summary information with respect to our proved reserves as of December 31, 2010 and 2009, as estimated by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers. A copy of their summary reserve report for 2010 is included as an exhibit to this Annual Report on Form 10-K. See Note 15 Oil and Gas Producing Activities (Unaudited) to our consolidated financial statements for additional information.

	Proved Reserves at December 31, 2010			
	Developed Producing	Developed Non-Producing (dollars in thousands)	Undeveloped	Total
Net Proved Reserves:				
Oil (MBbls) (1)	703	43	872	1,618
Natural Gas (MMcf)	161,051	26,366	266,772	454,189
Natural Gas Equivalent (MMcfe) (2)	165,269	26,623	272,007	463,899
Estimated Future Net Cash Flows				$ 897,989
PV-10 (3)				$ 362,126
Discounted Future Income Taxes				(3,448)
Standardized Measure of Discounted Net Cash Flows (3)				$ 358,678

	Proved Reserves at December 31, 2009			
	Developed Producing	Developed Non-Producing (dollars in thousands)	Undeveloped	Total
Net Proved Reserves:				
Oil (MBbls)(1)	368	63	446	877
Natural Gas (MMcf)	142,134	20,801	252,366	415,301
Natural Gas Equivalent (MMcfe) (2)	144,343	21,176	255,042	420,561
Estimated Future Net Cash Flows				$ 424,983
PV-10 (3)				$ 148,165
Discounted Future Income Taxes				(941)
Standardized Measure of Discounted Net Cash Flows (3)				$ 147,224

(1) Includes condensate.
(2) Based on ratio of six Mcf of natural gas per Bbl of oil.
(3) 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 is 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, 2010 was $358.7 million. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

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The following table presents our reserves by targeted geologic formation in Mmcfe.

	December 31, 2010			
Area	**Proved Developed**	**Proved Undeveloped**	**Proved Reserves**	**% of Total**
Haynesville Shale Trend	79,089	151,168	230,257	50%
Cotton Valley Taylor Sand	23,718	117,643	141,361	30%
Eagle Ford Shale Trend	2,855		2,855	1%
Other	86,230	3,196	89,426	19%
Total	191,892	272,007	463,899	100%

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.

In accordance with the guidelines of the SEC, our independent reserve engineers estimates of future net revenues from our estimated proved reserves, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the period January 2010 through December 2010, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The average oil and natural gas prices used in such estimates as of December 31, 2010 were $4.38 per Mmbtu, of natural gas and $75.96 per Bbl of crude oil/condensate. These prices do not include the impact of hedging transactions, nor do they include the adjustments that are made for applicable transportation and quality differentials, and price differentials between natural gas liquids and oil, which are deducted from or added to the index prices on a well by well basis in estimating our proved reserves and related future net revenues.

Our proved reserve information as of December 31, 2010 included in this Annual Report on Form 10-K was estimated wholly by our independent petroleum consultant, NSAI, in accordance with petroleum engineering and evaluation principles and definitions and guidelines set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The Company s principal engineer has over 30 years of experience in the oil and gas industry, including over 25 years as a reserve evaluator, trainer or manager. Further professional qualifications of our principal engineer include a degree in petroleum engineering, extensive internal and external reserve training, and experience in asset evaluation and management. In addition, the principal engineer is an active participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 30 years.

Our estimates of proved reserves are made wholly by Netherland, Sewell & Associates, Inc. (NSAI), as the Company s independent petroleum engineers. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria is provided to them. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

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The Company considers the best control to ensure compliance with Rule 4-10 of Regulation S-X for reserve estimates is providing independent fully engineered third-party estimate of reserves from a nationally reputable petroleum engineering firm.

While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the NSAI reserve report is reviewed by our senior management with representatives of NSAI and internal technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves semi-annually.

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, available downhole and production data, seismic data and well test data.

Our proved undeveloped reserves at December 31, 2010, as estimated by NSAI, were 272.0 Bcfe, consisting of 266.8 Bcf of natural gas and 0.9 MMBbls of oil and condensate. In 2010 we added approximately 40 Bcfe related to the Haynesville and Cotton Valley Taylor Sand formations, we had revisions of approximately 7 Bcfe and we developed approximately 16 Bcfe or 6.2% of our total proved undeveloped reserves booked as of December 31, 2009 through the drilling of 6 gross (3.5 net) development wells at an aggregate capital cost of approximately $25.4 million. During 2010, we sold oil and natural gas properties which included 32.5 Bcfe of natural gas of proved developed reserves. None of our proved undeveloped reserves at December 31, 2010 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves, or are scheduled for commencement of development in our December 31, 2010 reserve report on a date more than five years from the date the reserves were initially booked as proved undeveloped.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2010:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
South Texas	6	4.1			6	4.1
East Texas	2	1.1	250	238.2	252	239.3
Northwest Louisiana			101	42.5	101	42.5
Other	8	3.3	15	0.2	23	3.5
Total Productive Wells	16	8.5	366	280.9	382	289.4

(1) We only engineer royalty and overriding interest wells that have PV-10 large enough to include in the reserve report consequently only 4 wells with royalty and overriding interest are included.

(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, 46 wells had completions in multiple producing horizons.

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Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2010. 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
South Texas	1,240	902	65,796	36,892	67,036	37,794
East Texas	94,584	55,788	50,213	31,827	144,797	87,615
Northwest Louisiana	53,611	24,383	11,624	6,993	65,235	31,376
Other			1,920	19	1,920	19
Total	149,435	81,073	129,553	75,731	278,988	156,804

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.

Lease Expirations

Our undeveloped acreage, including optioned acreage, expires during the next four years at the rate of 13,238 net acres in 2011 and 14,683 net acres in 2012, 4,107 net acres in 2013 and 448 net acres in 2014, unless included in producing units or extended prior to lease expiration. Substantially all of the 2011 lease expirations are within the Cotton and Cotton South fields where the Company recently sold all of its shallow rights and where it has no current plans to drill any deep wells.

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. Chesapeake Energy Corporation (Chesapeake) continues to operate under our joint development agreement and drill Haynesville Shale wells on our jointly-owned North Louisiana acreage.

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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,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	44	18.9	43	23.6	107	65.9
Non-Productive					2	1.1
Total	44	18.9	43	23.6	109	67.0
Exploratory Wells:						
Productive	3	2.3	2	1.0	17	8.4
Non-Productive						
Total	3	2.3	2	1.0	17	8.4
Total Wells:						
Productive	47	21.2	45	24.6	124	74.3
Non-Productive					2	1.1
Total	47	21.2	45	24.6	126	75.4

At December 31, 2010, the Company had 4 gross (2.2 net) development wells in process of being drilled.

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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 properties (including each of the two fields which are attributed more than 15% of our total proved reserves as of December 31, 2010), 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, 2010.

	Sales Volumes			Average Sales Prices (1)			Average
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Natural Gas Mcf	Oil & Condensate Per Bbl	Total Per Mcfe	Production Cost (2) Per Mcfe
For Year 2010							
Haynesville Shale Trend	17,295	1	17,300	$ 3.83	$ 64.00	$ 3.83	$ 0.15
Cotton Valley Taylor Sand	2,386	24	2,529	4.38	62.17	4.72	0.16
Eagle Ford Shale Trend	131	39	368	3.53	68.26	8.49	0.62
Other	13,003	86	13,519	4.56	84.53	4.93	1.70
Total	32,815	150	33,716	$ 4.16	$ 76.59	$ 4.39	$ 0.78
For Year 2009							
Haynesville Shale Trend	7,960	1	7,966	$ 2.13	$ 55.00	$ 2.14	$ 0.19
Cotton Valley Taylor Sand	926	3	945	2.68	54.33	2.79	0.18
Eagle Ford Shale Trend							
Other	20,005	147	20,885	4.16	53.63	4.37	1.37
Total	28,891	151	29,796	$ 3.55	$ 53.65	$ 3.72	$ 1.01
For Year 2008							
Haynesville Shale Trend	157		157	8.11		8.11	0.78
Cotton Valley Taylor Sand							
Eagle Ford Shale Trend							
Other	23,017	167	24,019	8.59	97.70	8.92	1.32
Total	23,174	167	24,176	$ 8.59	$ 97.70	$ 8.91	$ 1.32

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

In addition, two of our fields, the Bethany Longstreet and Beckville fields each account for more than 15% of our estimated proved reserves as of December 31, 2010. The table below provides production volume data for each of the fields for the years presented:

	Sales volumes		
	Natural Gas (Mmcf)	Oil & Condensate (MBbls)	Total (Mmcfe)
For Year 2010			

Bethany Longstreet	10,398	2	10,412
Beckville	6,259	37	6,483
For Year 2009			
Bethany Longstreet	6,538	5	6,567
Beckville	4,946	47	5,225
For Year 2008			
Bethany Longstreet	2,884	5	2,914
Beckville	4,176	39	4,413
For Year 2007			
Bethany Longstreet	2,875	7	2,914
Beckville	4,340	37	4,560

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For a discussion of comparative changes in our sales volumes, revenues and operating expenses for the three years ended December 31, 2010, 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 the largest of these sources as a percent of oil and gas revenues for the year ended December 31, 2010 was as follows:

	2010
Louis Dreyfus Corporation	29%
Shell Energy	17%

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.

Employees

At February 17, 2011, we had 116 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.

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.

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Environmental Matters

General

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 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 and production 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 assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that may limit or prohibit some or all of our operations.

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.

Hazardous Substances and Wastes

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 companies 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 liabilities 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. While there exists an exclusion under RCRA from the definition of hazardous wastes for certain materials generated in the exploration, development or production of oil and gas, these wastes may be regulated by the U.S. Environmental Protection Agency (the EPA) and state environmental agencies as non-hazardous solid wastes. Moreover, we generate petroleum product wastes and ordinary industrial wastes that may be regulated as solid and hazardous wastes. The EPA and state agencies have imposed stringent requirements for the disposal of hazardous and solid 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 and petroleum 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 recycling or disposal. In addition, some of our properties have been operated by third parties whose treatment and disposal of hazardous substances, wastes and petroleum 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.

Water Discharges

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.

The disposal of oil and gas wastes into underground injection wells are subject to the Safe Drinking Water Act as well as analogous state laws. Under Part C of the Safe Drinking Water Act, the EPA established the Underground Injection Control Program, which establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury. In addition to the underground injection operations, our activities include the performance of hydraulic fracturing services to enhance any production of natural gas from formations with low permeability, such as shales. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injunction Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could increase our costs of compliance, impose operational delays, and make it more difficult to perform hydraulic fracturing, resulting in reduced amounts of oil and natural gas being produced.

Air Emissions

The Federal Clean Air Act, as amended, and comparable state laws, regulates emissions of various air pollutants from many sources in the United States, including crude oil and natural gas production activities. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. 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.

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Climate Change. In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth s atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the CAA that require a reduction in emissions of GHGs from motor vehicles and also trigger construction and operating permit review for GHG emissions from certain stationary sources, effective January 2, 2011. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. The EPA s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing or requiring state environmental agencies to implement the rules. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production interests and operations.

Endangered Species

The federal Endangered Species Act and analogous state laws restrict activities that could have an adverse effect on threatened or endangered species or their habitats. While some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

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

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Other Laws and Regulations

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.

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning the Company s operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words may, could, believes, expects, anticipates, intends, estimates, projects, predicts, target, goal, plans, objective, potential, should, or similar expressions or variations on such expressions that convey the uncertainty of future events or outcomes. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; the Company undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company s expectations include, but are not limited to, the following risk and uncertainties:

- *planned capital expenditures;*
- *future drilling activity;*
- *our financial condition;*
- *business strategy , including the Company s ability to successfully transition to more liquids-focused operations*

the market prices of oil and natural gas;

uncertainties about the estimated quantities of oil and natural gas reserves;

financial market conditions and availability of capital;

production;

hedging arrangements;

future cash flows and borrowings;

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litigation matters;

pursuit of potential future acquisition opportunities;

sources of funding for exploration and development;

general economic conditions, either nationally or in the jurisdictions in which the Company or its subsidiary are doing business;

legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;

the creditworthiness of the Company s financial counterparties and operation partners;

the securities, capital or credit markets;

the Company s ability to repay its debt, including its convertible senior notes due 2026 that it may be required to repurchase in December 2011; and

other factors discussed below and elsewhere in this Form 10-K and in the Company s other public filings, press releases and discussions with Company management.

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 NSAI, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and gas prices in 2010. These prices will change and may be lower at the time of production than those prices that prevailed during 2010. 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

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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 12-month average 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 operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies or price gathering-rate controls. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act), was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile

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and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our common stock.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition.

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Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that require a reduction in emissions of GHGs from motor vehicles and also may trigger Prevention of Significant Deterioration (PSD) and Title V permit requirements for GHG emissions from certain stationary sources when the motor vehicle standards took effect on January 2, 2011. The EPA rules have tailored the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA also published a final rule on November 30, 2010 expanding its existing GHG emissions reporting rule to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely demand for the oil and natural gas we produce.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could increase our costs of compliance, impose operational delays, and make it more difficult to perform hydraulic fracturing, resulting in reduced amounts of oil and natural gas being produced.

Our estimates of proved reserves have been prepared under SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This report presents estimates of our proved reserves as of December 31, 2010, which have been prepared and presented under SEC rules. These rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on twelve-month unweighted first-day-of-the-month average pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2010 and 2009 was based on an unweighted average twelve month

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West Texas Intermediate (WTI) posted price of $75.96 per Bbl for oil and a Henry Hub Spot price of $4.38 per MMBtu for natural gas, as compared to $57.65 per Bbl for oil and $3.87 per MMBtu for natural gas as of December 31, 2009. As a result of these changes, direct comparisons of our reserves amounts under the rules may be more difficult.

Another impact of the SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in shale plays in East Texas, Northwest Louisiana and South Texas. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the rules and may not issue further interpretive guidance on the rules. Accordingly, while the estimates of our proved reserves at December 31, 2010 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific future SEC interpretive guidance.

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

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

- lack of acceptable prospective acreage;
- inadequate capital resources;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- 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;
- mechanical difficulties; and
- risks associated with horizontal drilling.

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, while lower oil and gas prices may reduce the amount of oil and natural gas that we can produce economically, 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

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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 sustained 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 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.

Natural gas and crude oil prices are extremely volatile. Average natural gas and oil prices varied substantially during the past few years. Any actual or anticipated reduction in natural gas and crude oil and prices may further depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future.

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Prices for natural gas increased slightly in 2010 but still have remained low when compared with average prices in prior years. These lower prices, coupled with the slow recovery in financial markets that has significantly limited and increased the cost of capital, have compelled most natural gas and oil producers, including us, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Any sustained reductions in natural gas and oil prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under our senior credit facility, which would restrict our liquidity. Additionally, further or continued declines in prices could result in non-cash charges to earnings due to impairment write downs. Any such writedown could have a material adverse effect on our results of operations in the period taken.

Our use of gas and oil 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 natural gas and oil 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. We hedged approximately 43% of our total production volumes for the year ended December 31, 2010.

Our results of operations may be negatively impacted by our commodity 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 natural gas and oil. For the years ended December 31, 2010 and 2009, we realized a gain on settled natural gas derivatives of $24.6 million and $98.0 million, respectively. For the year ended December 31, 2008, we realized a loss on settled commodity derivatives of $1.8 million.

For the year ended December 31, 2010, we recognized in earnings an unrealized gain on commodity derivative instruments not designated as hedges of $30.7 million. For financial reporting purposes, this unrealized gain was combined with a $24.6 million realized gain resulting in a total gain on commodity derivative instruments not designated as hedges of $55.3 million for 2010.

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For the year ended December 31, 2009, we recognized in earnings an unrealized loss on commodity derivative instruments not designated as hedges of $50.2 million. For financial reporting purposes, this unrealized loss was combined with a $98.0 million realized gain resulting in a total gain on commodity derivative instruments not designated as hedges of $47.8 million for 2009.

For the year ended December 31, 2008, we recognized in earnings an unrealized gain on commodity derivative instruments not designated as hedges of $55.4 million. For financial reporting purposes, this unrealized gain was combined with a $1.8 million realized loss resulting in a total gain on commodity derivative instruments not designated as hedges of $53.6 million for 2008.

We account for our natural gas and oil derivatives using fair value accounting standards. Each derivative is recorded on the balance sheet as an asset or liability at its fair value. Additionally, changes in a derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. We have elected not to apply hedge accounting treatment to our swaps and collars and, as such, all changes in the fair value of these instruments are recognized in earnings. Our fixed price physical contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

In the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our derivative instruments. See Note 8 Derivative Activities to our consolidated financial statements for further discussion.

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. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. 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.

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 58.5% of our total estimated proved reserves by volume at December 31, 2010, were undeveloped. By their nature, estimates of proved undeveloped reserves and timing of their production are less certain particularly because we may chose not to develop such reserves on anticipated schedules in future adverse oil or natural gas price environments. Recovery of such reserves will require significant capital expenditures and successful drilling operations. The lack of availability of sufficient capital to fund such future operations could materially hinder or delay our replacement of produced reserves. 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 proved 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. Furthermore, any sustained decline in oil and natural gas prices may require us to make further impairments. 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, 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, 2010, 2009 and 2008, we recorded impairments related to oil and gas properties of $234.9 million, $208.9 million and $28.6 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.

Essentially all of our estimated proved reserves at December 31, 2010, and all our production during 2010 were associated with our Northwest Louisiana, East Texas and South Texas properties which include the Haynesville Shale and Eagle Ford Shale, respectfully. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention (including potential regulation or limitation of the use of high pressure fracture stimulation techniques in these formations) or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For example, Chesapeake and Matador Resources Company operate certain properties in the Haynesville Shale. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

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Our ability to sell natural gas and receive market prices for our gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

We operate primarily in the Northwest Louisiana, East Texas and South Texas areas. Northwest Louisiana and East Texas is in the same geographic region as the Haynesville Shale. A number of companies are currently operating in the Haynesville Shale. If drilling in the Haynesville Shale and Eagle Ford Shale continues to be successful, the amount of natural gas being produced could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in this region. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Northwest Louisiana and East Texas may not occur or may be substantially delayed for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those quoted on NYMEX or that we currently project, which would adversely affect our results of operations.

A portion of our natural gas and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

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

On February 4, 2011, we entered into a third amendment to our senior credit facility revising our interest coverage ratio from 3.0x to 2.5x to take into consideration additional non-cash interest related to the adoption of APB 14-1 in December 2009.

Our senior credit facility contains customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our senior credit facility. As of December 31, 2010, we were in compliance with all the financial covenants of our senior credit facility. These restrictions may make it difficult for us to successfully execute our business strategy or to compete in our industry with companies not similarly restricted. In addition, our current senior credit facility matures in August 2011. Any replacement credit facility may have more restrictive covenants or provide us with less borrowing capacity.

We will need to obtain additional borrowings or other funding in the event holders of our $175 million 3.25% Convertible Senior Notes Due 2026 require us to purchase some or all of the notes on December 1, 2011.

Holders of our $175 million principal amount 3.25% Convertible Senior Notes Due 2026 have the right to require us to purchase some or all of such notes at par on December 1, 2011. Because the conversion price of those notes is substantially above recent trading price of our common stock, it is more likely that notes will be put to us for repurchase on such date. Accordingly, we must incur additional borrowings or seek other sources of funding to repay any such notes that are required to be repurchased. These additional borrowings may be on terms less favorable than our current indebtedness or may be subject to more restrictive covenants. Obtaining funding from other sources, such as the sale or participation of some of our properties or assets, could have an adverse impact on our capital spending for exploration and development.

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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 in exact 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 relating to the acquired assets and indemnities are unlikely to cover liabilities relating to the time periods after closing. We may be required to assume any risk relating to 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.

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.

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.

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.

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We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

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***

A discussion of current legal proceedings is set forth in Part II, Item 8 Financial Statements, under Note 9 Commitments and Contingencies to our Consolidated Financial Statements in this Form 10-K.

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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 February 14, 2011, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,332 and 37,672,853 shares outstanding. High and low sales prices for our common stock for each quarter during 2010 and 2009 were as follows:

	2010		2009	
	High	Low	High	Low
First Quarter	$ 25.83	$ 15.52	$ 34.07	$ 14.93
Second Quarter	19.19	11.26	30.03	19.27
Third Quarter	14.81	11.16	27.56	21.43
Fourth Quarter	17.71	12.51	30.38	20.38

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, 2010. 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 payroll tax withholding obligation. The company then remits the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2010, we withheld 65,589 shares of common stock from issuance in this manner and paid $1.1 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.

Performance

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the company specifically incorporates it by reference into such filing.

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The following graph compares the cumulative five-year total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 Index and the S&P Small-Cap Index. An investment of $100 is assumed to have been made in the Company s common stock and the indexes on December 31, 2005 and its relative performance is tracked through December 31, 2010.

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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.

	Summary Financial Information				
	2010	2009	2008	2007	2006
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 148,031	$ 110,784	$ 215,369	$ 110,691	$ 73,933
Other	302	(358)	682	614	838
	148,333	110,426	216,051	111,305	74,771
Operating Expenses:					
Lease operating expense	26,306	30,188	31,950	22,465	12,688
Production and other taxes	3,627	4,317	7,542	2,272	3,345
Transportation	9,856	9,459	8,645	5,964	3,791
Depreciation, depletion and amortization	105,913	160,361	107,123	79,766	37,225
Exploration	10,152	9,292	8,404	7,346	5,888
Impairment of oil and gas properties	234,887	208,905	28,582	7,696	9,886
General and administrative	30,918	27,923	24,254	20,888	17,223
Loss (gain) on sale of assets	2,824	(297)	(145,876)	(42)	(23)
Other	4,268			109	
	428,751	450,148	70,624	146,464	90,023
Operating income (loss)	(280,418)	(339,722)	145,427	(35,159)	(15,252)
Other income (expense):					
Interest expense	(37,179)	(26,148)	(22,410)	(17,878)	(8,343)
Interest income and other	117	458	1,682	11,469	(7,660)
Gain (loss) on derivatives not designated as hedges	55,275	47,115	51,547	(6,439)	38,128
Loss on early extinguishment of debt					(612)
	18,213	21,425	30,819	(12,848)	21,513
Income (loss) before income taxes	(262,205)	(318,297)	176,246	(48,007)	6,261
Income tax (expense) benefit	85	67,311	(54,472)	9,294	(4,940)
Net income (loss)	(262,120)	(250,986)	121,774	(38,713)	1,321
Preferred stock dividends	6,047	6,047	6,047	6,047	6,016
Preferred stock redemption premium					1,545
Net income (loss) applicable to common stock	$ (268,167)	$ (257,033)	$ 115,727	$ (44,760)	$ (6,240)
PER COMMON SHARE					
Net income (loss) applicable to common stock basic	$ (7.47)	$ (7.17)	$ 3.42	$ (1.75)	$ (0.25)
Net income (loss) applicable to common stock diluted	$ (7.47)	$ (7.17)	$ 3.23	$ (1.75)	$ (0.25)
Weighted average common shares outstanding basic	35,921	35,866	33,806	25,578	24,948

Weighted average common shares outstanding diluted	35,921	35,866	40,397	25,578	25,412
Balance Sheet Data:					
Total assets	$ 664,577	$ 860,274	$ 1,038,287	$ 589,233	$ 478,573
Total long-term debt	179,171	330,147	226,723	185,449	165,216
Stockholders equity	183,972	445,385	665,348	312,781	228,026

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

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this report in Item 8, and the information set forth in *Risk Factors* under Item 1A.

Overview

We are an independent oil and gas company engaged in the exploration, development and production of oil and natural gas properties primarily in Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley trends and South Texas which includes the Eagle Ford Shale trend.

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 development 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 because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses) and impairments.

Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects with available capital, 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.

Business strategy

Our business strategy is to provide long term growth in reserves on a cost-effective basis. We focus on adding reserve value through the development of our Haynesville Shale and Eagle Ford Shale acreage and the timely development of our large relatively low risk development program in the East Texas and North Louisiana and South Texas area. We regularly evaluate possible acquisitions of prospective acreage and oil and gas drilling opportunities.

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

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 Eagle Ford Shale, Haynesville Shale and Cotton Valley Taylor sand on our acreage in order to develop our natural gas and oil reserves. We estimate that our Eagle Ford Shale acreage currently includes over 400 gross unrisked, non-proved drilling locations. Our Haynesville Shale acreage currently includes more than 1,200 gross unrisked, non-proved drilling locations based on anticipated well spacing and our Cotton Valley Taylor sand inventory includes more than 200 gross unrisked, non-proved drilling locations based on anticipated well spacing.

Increase our oil production. During the past year, we have concentrated on increasing our crude oil production and reserves by investing and drilling in the Eagle Ford Shale. We intend to take advantage of the more favorable sales price of oil compared to the relative sales price of natural gas.

Expand acreage position in the Haynesville and Eagle Ford shale plays. We have increased our acreage position in the Haynesville Shale to 158,749 gross (88,722 net) lease acres and own approximately 67,000 gross (38,000 net) of lease acres in the Eagle Ford Shale as of December 31, 2010. We continue to 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 within our existing areas of operation that exhibit 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 maximizing cash flow margins. We intend to maximize cash flow margins by focusing on higher-margin oil development in the Eagle Ford Shale trend and lowering our overall operating costs in our natural gas properties. In the current commodity price environment, our Eagle Ford Shale assets offer more attractive cash flow margins than our natural gas assets. From 2008 to 2010, we lowered our lease operating costs on a consolidated basis from $1.32 per Mcfe to $0.78 per Mcfe by focusing on lower cost Haynesville Shale potential and divesting higher cost mature assets. We expect this trend to continue as it relates to our natural gas properties.

Maintain financial flexibility. As of December 31, 2010, we had a borrowing base of $225 million under our senior credit facility, of which none was outstanding. We have historically funded growth through cash flow from operations, equity and equity-linked security issuances, divestments of non-core assets and entering into strategic joint ventures. 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.

2010 Overview

We achieved annual production volume growth of 13% with production volume growing from 29.8 Bcfe in 2009 to 33.7 Bcfe in 2010.

We ended the year with estimated proved reserves of approximately 463.9 Bcfe (approximately 454.2 Bcf of natural gas and 1.6 MMBbls of oil and condensate), with a PV-10 of $362.1 million and a standardized measure of $358.7 million, approximately 41% of which is proved developed.

We conducted drilling operations on 36 gross wells (12.7 net) in the Haynesville Shale trend and added 23 gross (8.8 net) wells to production in 2010. As of December 31, 2010, we had 13 gross (4.0 net) wells drilled but awaiting completion.

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We acquired lease acreage in the Eagle Ford Shale trend where we conducted drilling operation on 6 gross (4.1 net wells) all of which were added to production in 2010.

We sold our shallow rights in our non-core high cost properties for approximately $70 million before normal closing adjustments recognizing a loss on sale of assets of $2.8 million.

We reduced our lease operating expense per Mcfe by 23% from $1.01 in 2009 to $0.78 per Mcfe in 2010.

We recorded an impairment expense of $234.9 million on our non-core properties

We decreased our depletion expense by 42% from $5.38 per Mcfe in 2009 to $3.14 per Mcfe in 2010.

Eagle Ford Shale Trend

During the second half of 2010, the Company commenced drilling operations on its acreage in the Eagle Ford Shale Trend. The Company s leasehold position is located in both La Salle and Frio counties, Texas. During 2010, the Company conducted drilling operations on approximately 8 gross (6 net) operated Eagle Ford Shale Trend wells. During December 2010, the Company commenced drilling operations with a second rig on its Eagle Ford Shale Trend acreage. In 2011, the Company plans to spend approximately $145 million on 20 to 24 gross wells.

Haynesville Shale Trend

Our relatively low risk development drilling program in this trend is primarily centered in and around Rusk, Panola, Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We continue to build our acreage position in this trend and hold 158,749 gross acres as of December 31, 2010 producing from and prospective for the Haynesville Shale. As of year- end 2010, we drilled and completed a cumulative total of 85 wells in the trend with a 100% success rate. Our net production volumes from our Haynesville Shale wells aggregated approximately 47,000 Mcfe per day in 2010, or approximately 51% of our total oil and gas production for the year. Our 2011 capital expenditure budget includes plans to utilize approximately 1 to 3 rigs to conduct drilling operations on approximately 7 to 9 gross additional Haynesville Shale horizontal wells.

Core Haynesville Shale

The Company s core Haynesville shale drilling program is primarily concentrated in the Bethany-Longstreet and Greenwood-Waskom fields in Caddo and DeSoto Parishes in northwest Louisiana. The Company s core Haynesville Shale drilling activity includes both operated and non-operated drilling in and around its core acreage positions in northwest Louisiana. The Company continues to build its acreage position in the trend and currently holds approximately 30,000 gross (16,000 net) acres as of December 31, 2010. The Company s net production volumes from its core Haynesville Shale wells totaled approximately 37,000 Mcfe per day in 2010, or approximately 40% of the Company s total production for the year. In 2011, the Company estimates that it will spend approximately $25 to 30 million on 5 to 7 gross wells.

Shelby Trough / Angelina River Trend

During the second half of 2010, the Company spud its first Haynesville & Bossier Shale wells in the Shelby Trough / Angelina River Trend area. The Company operates all of its drilling activities, which are primarily located in Nacogdoches, Angelina and Shelby counties, Texas. The Company continues to build its acreage position in the trend and currently holds approximately 48,500 gross (27,000 net) acres as of December 31, 2010. The Company s net production volumes from its Shelby Trough wells totaled approximately 1,300 Mcfe per day in 2010, or approximately 1% of the Company s total production for the year. In 2011, the Company estimates that it will spend approximately $20 to 30 million on 2 to 3 gross wells.

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Cotton Valley Taylor Sand

During 2010, the Company conducted drilling operations on four horizontal Cotton Valley Taylor Sand wells throughout its acreage position in the Minden, Beckville and South Henderson fields of East Texas. In the South Henderson field, the Company s Travis Crow 1H well reached initial production of over 12.0 MMcfe/day, which included approximately 380 Bbls of oil per day. In 2011, the Company plans to spend approximately $20 25 million to drill three offset wells in its South Henderson field. The Company has approximately 56,000 gross (49,000) net acres prospective for the Cotton Valley Taylor Sand. The Company s net production volumes from its Cotton Valley Taylor Sand wells totaled approximately 7,000 Mcfe per day in 2010, or approximately 8% of the Company s total oil and gas production for the year.

During 2010, we drilled and completed 4 gross (4 net) oil wells with a 100% success rate in the play. Our 2011 capital expenditure budget includes plans to utilize approximately 1 rig to conduct drilling operations on approximately 3 gross (3 net) additional Cotton Valley horizontal wells.

Results of Operations

For the year ended December 31, 2010, we reported net loss applicable to common stock of $268.2 million, or $7.47 per share (basic and diluted), on operating revenues of $148.3 million. This compares to net loss applicable to common stock of $257.0 million, or $7.17 per share (basic and diluted, for the year ended December 31, 2009 and a net income applicable to common stock of $115.7 million, or $3.42 per share (basic) and $3.23 per share (diluted) for the year ended December 31, 2008.

The following table reflects our summary operating information for the periods presented in thousands except for price and volume data.

	Year End December 31,				Year End December 31,			
Summary Operating Information:	**2010**	**2009**	**Variance**		**2009**	**2008**	**Variance**	
Revenues:								
Natural gas	$ 136,527	$ 102,692	$ 33,835	33%	$ 102,692	$ 199,057	$ (96,365)	(48%)
Oil and condensate	11,504	8,092	3,412	42%	8,092	16,312	(8,220)	(50%)
Natural gas, oil and condensate	148,031	110,784	37,247	33%	110,784	215,369	(104,585)	(49%)
Operating revenues	148,333	110,426	37,907	34%	110,426	216,051	(105,625)	(49%)
Operating expenses	428,751	450,148	(21,397)	(5%)	450,148	70,624	379,524	537%
Operating income (loss)	(280,418)	(339,722)	(59,304)	(17%)	(339,722)	145,427	(485,149)	(334%)
Net income (loss) applicable to common stock	(268,167)	(257,033)	(11,134)	4%	(257,033)	115,727	(372,760)	(322%)
Net Production:								
Natural gas (MMcf)	32,815	28,891	3,924	14%	28,891	23,174	5,717	25%
Oil and condensate (MBbls)	150	151	(1)	(1%)	151	167	(16)	(10%)
Total (MMcfe)	33,716	29,796	3,920	13%	29,796	24,176	5,620	23%
Average daily production (Mcfe/d)	92,373	81,632	10,741	13%	81,632	66,054	15,578	24%
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$ 4.16	$ 3.55	$ 0.61	17%	$ 3.55	$ 8.59	$ (5.04)	(59%)
Oil and condensate (per Bbl)	76.59	53.65	22.94	43%	53.65	97.70	(44.05)	(45%)
Average realized price (per Mcfe)	4.39	3.72	0.67	18%	3.72	8.91	(5.19)	(58%)

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Oil and Gas Revenue

Oil and gas revenues increased $37.2 million or 33% to $148.0 million in 2010 compared to $110.8 million in 2009. The 18% increase in average sales price compared to 2009 contributed approximately $22.7 million to the increase in oil and gas revenue while the net production increase of 13% compared to 2009 contributed approximately $15.5 million to the increase in oil and gas revenue. Our average realized sales price was $4.39 per Mcfe in 2010 compared to $3.72 per Mcfe in 2009. Sales prices are dictated by the market. We increased production by the continued development of our Haynesville Shale assets. The drilling and completion of 40 wells in our Northwest Louisiana and East Texas, 36 of which were in the Haynesville Shale, resulted in the continued trend of annual natural gas production growth for the Company.

Oil and gas revenues decreased $104.6 million to $110.8 million in 2009, a decrease of 49% from 2008. The oil and gas revenue reduction attributable to the realized price decrease was $125.5 million while the increase in production offset that decrease by $20.9 million. We did increase our daily production average to 81.6 MMcfe per day in 2009 from 66.1 Mmcfe per day in 2008, or 24%. The drilling and completion of 45 wells in our Northwest Louisiana and East Texas area, 32 of which were in the Haynesville Shale, resulted in the continued trend of annual natural gas production growth for the Company.

Operating Expenses

Operating expenses of $428.8 million in 2010 included a $234.9 million asset impairment, a $2.8 million loss on sale of assets and other expense of $4.3 million. Eliminating these non-comparable items from the operating expenses in both 2010 and 2009, the adjusted operating expense of $186.8 million in 2010 decreased 23% or $54.7 million from adjusted operating expense of $241.5 million in 2009. This decrease is primarily attributed to lower lease operating expense on our Haynesville Shale wells and decreased depreciation, depletion and amortization (DD&A) expense because of a lower DD&A rate. The DD&A rate reduction was primarily due to the impairment writedown of the carrying value of our oil and gas properties and the addition of the Haynesville Shale reserves with its relatively lower pending costs.

Operating expenses totaled $450.1 million for the year ended December 31, 2009. Operating expenses of $70.6 million in 2008 included a $145.9 million gain on sale of assets. Excluding the gain on sales of assets and impairment expense for both 2009 and 2008, operating expense of $241.5 million in 2009 increased 29% or $53.6 million over operating expense of $187.9 million in 2008. This increase is primarily attributed to increased DD&A expense because of a higher DD&A rate and increased production in 2009. Our operating loss of $339.7 million in 2009 is primarily attributed to the previously mentioned impairment charge totaling $208.9 million, a substantial reduction in revenues in 2009 versus 2008 and the increased DD&A expense.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	2010	2009	Variance		2009	2008	Variance	
Lease operating expenses	$ 26,306	$ 30,188	$ (3,882)	(13%)	$ 30,188	$ 31,950	$ (1,762)	(6%)
Production and other taxes	3,627	4,317	(690)	(16%)	$ 4,317	7,542	(3,225)	(43%)
Transportation	9,856	9,459	397	4%	$ 9,459	8,645	814	9%
Exploration	10,152	9,292	860	9%	$ 9,292	8,404	888	11%

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	2010	2009	Variance		2009	2008	Variance	
Lease operating expenses	$ 0.78	$ 1.01	$ (0.23)	(23%)	$ 1.01	$ 1.32	$ (0.31)	(23%)
Production and other taxes	0.11	0.14	(0.03)	(21%)	0.14	0.31	(0.17)	(55%)

Transportation	0.29	0.32	(0.03)	(9%)	0.32	0.36	(0.04)	(11%)
Exploration	0.30	0.31	(0.01)	(3%)	0.31	0.35	(0.04)	(11%)

Lease Operating Expense

Lease operating expense (LOE) for the year 2010 was $26.3 million, a decrease of $3.9 million or 13% from the $30.2 million for the year 2009. On a per unit basis, LOE decreased 23% from $1.01 to $0.78 per Mcfe for the year 2010 compared to 2009. The overall cost decrease is attributable to lower saltwater disposal cost as we realized a $2.1 million savings from the continued impact of a series of saltwater disposal systems installed in 2009 and a $1.8 million savings in compression costs as a result of more favorable rental contract rates. On a per unit basis, LOE decreased for the year 2010 compared to the year 2009 as a result of cost reductions, a 13% increase in production volumes and an increasing portion of our production coming from the lower production cost Haynesville Shale wells. We expect the LOE per unit of production to continue to decrease as a result of the lower cost Haynesville Shale making up a larger portion of our total production and having sold our higher cost non-core properties in December 2010.

LOE for the year 2009 was $30.2 million, a decrease of $1.8 million or 6% from the $32.0 million for the year 2008. On a per unit basis, LOE decreased 23% from $1.32 to $1.01 per Mcfe for the year 2009 compared to 2008. The overall cost decrease is attributable to lower saltwater disposal cost as we realized the continued impact of a new series of saltwater disposal system installations in 2009 and lower compressor rental costs negotiated in conjunction with current market conditions. The decrease in the unit cost between the years is attributable to the absolute dollar cost reduction, a 23% increase in production volumes and an increasing portion of our production coming from the Haynesville Shale, which carries lower production costs.

Production and Other Taxes

Production and other taxes for the year 2010 were $3.6 million which includes production tax of $1.1 million and ad valorem tax of $2.5 million. Production tax in 2010 is net of $1.6 million of tax credits attributed to Tight Gas Sands (TGS) credits for our wells in the State of Texas and $0.4 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. During the year 2009, production and other taxes were $4.3 million, which included production tax of $1.3 million and ad valorem tax of $3.0 million. Production tax in 2009 is net of $1.6 million of tax credits attributed to TGS credits for our wells in the State of Texas and $0.2 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. The lower production tax for 2010 compared to 2009 is attributable to the increasing portion of our production coming from the Haynesville Shale horizontal wells, which are exempt for two years from State of Louisiana production tax.

The TGS tax 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. We anticipate that we will incur a gradually lower production tax rate in the future as we add additional Texas qualifying wells to our production base and as reduced rates are approved.

The Louisiana horizontal wells are eligible for a two year severance tax exemption from the date of first production or until payout of qualified costs, whichever is first.

Ad valorem taxes decreased $0.5 million to $2.5 million in 2010 from $3.0 million in 2009. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. Though the number of properties we owned increased from January 1, 2009 to January 1, 2010, the assessed values for our properties were lower year-to-year driven by decreased commodity prices.

During the year 2008, production and other taxes were $7.5 million, which included production tax of $5.5 million and ad valorem tax of $2.0 million. Production tax for 2008 is net of $3.2 million of TGS credits for our wells in the State of Texas. The lower production tax for 2009 compared to 2008 is attributable to decreased gas prices year- to- year. Also, an increasing portion of our production is attributable to Haynesville Shale horizontal wells, which are exempt for two years from State of Louisiana production tax.

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Ad valorem taxes increased $1.0 million to $3.0 million in 2009 from $2.0 million in 2008. The number of properties we owned increased from January 1, 2008 to January 1, 2009 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.

Transportation

Transportation expense increased 4% to $9.9 million ($0.29 per Mcfe) in 2010 compared to $9.5 million ($0.32 per Mcfe) in 2009. The increase in expense is primarily due to our higher production volumes and also up slightly due to a contractual annual volume deficiency charge related to non-core properties while the lower unit costs are a function of our changing geographic production mix, as well as a greater percentage of sales coming from non-operated properties from which the operator nets the transportation cost from revenues.

Transportation expense increased 9% to $9.5 million ($0.32 per Mcfe) in 2009 compared to $8.6 million ($0.36 per Mcfe) in 2008. The increase in expense is primarily due to our higher production volumes while the lower unit costs are a function of our changing geographic production mix, as well as a greater percentage of sales coming from non-operated properties from which the operator nets the transportation cost from revenues.

Exploration

Exploration expenses for 2010 increased $0.9 million to $10.2 million from $9.3 million for 2009, including a $6.0 million and $4.7 million for amortization of leasehold cost in 2010 and 2009, respectively.2010 exploration expenses include $1.3 million in seismic costs including exploratory seismic costs for our Angelina River area 3-D seismic program, slightly higher undeveloped leasehold cost amortization offset by a decrease in exploration labor cost as compared to 2009.

Exploration expenses for 2009 increased $0.9 million to $9.3 million from $8.4 million for 2008. 2009 exploration expenses include drilling contract early termination charges of $1.2 million.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	**2010**	**2009**	**Variance**		**2009**	**2008**	**Variance**	
Depreciation, depletion & amortization	$ 105,913	$ 160,361	$ (54,448)	(34%)	$ 160,361	$ 107,123	$ 53,238	50%
Impairment	234,887	208,905	25,982	12%	208,905	28,582	180,323	631%
General & administrative	30,918	27,923	2,995	11%	27,923	24,254	3,669	15%
Loss (gain) on sale of assets	2,824	(297)	3,121	1,051%	(297)	(145,876)	145,579	100%
Other	4,268		4,268	100%				

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	**2010**	**2009**	**Variance**		**2009**	**2008**	**Variance**	
Depreciation, depletion & amortization	$ 3.14	$ 5.38	$ (2.24)	(42%)	$ 5.38	$ 4.43	$ 0.95	21%
Impairment	6.97	7.01	(0.04)	(1%)	7.01	1.18	5.83	494%

General & administrative	0.92	0.94	(0.02)	(2%)	0.94	1.00	(0.06)	(6%)
Loss (gain) on sale of assets	0.08	(0.01)	0.09	900%	(0.01)	(6.03)	6.02	(100%)
Other	0.13		0.13	100%				

Depreciation, Depletion & Amortization

Our DD&A expense decreased $54.5 million to $105.9 million in 2010 from $160.4 million in 2009 as a result of a lower DD&A rate. The average DD&A rate decreased 42% while production increased 13% year-to-year. The decrease in the average depletion rate contributed $75.5 million to the decrease in DD&A expense offset by $21.0 million attributed to the higher production in 2010.

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We calculated the first six months of 2010 DD&A rates using the December 31, 2009 fully engineered reserves prepared by NSAI. Proved developed reserves increased 9% from 152.5 Bcfe at December 31, 2008 to 165.5 Bcfe at December 31, 2009. We calculated third quarter 2010 DD&A rates using the June 30, 2010 mid-year reserves prepared by internal reserve engineers. Proved developed reserves at June 30, 2010 were 205.8 Bcfe, a 24% increase over the reserves at December 31, 2009. We adjusted our DD&A rates in the fourth quarter of 2010 to reflect the impact of the impairment recorded in the third quarter of 2010.

The decrease in the 2010 DD&A rate was also impacted by the impairment recorded in the fourth quarter of 2009 and the addition of Haynesville Shale proved reserves, which carry more attractive finding and development costs per unit of proved reserves. The 2009 impairment was the result of the write down of our legacy vertical Cotton Valley and Travis Peak proved reserves which reduced the book value of the oil and gas properties to be depleted.

DD&A expense increased $53.3 million to $160.4 million in 2009 from $107.1 million in 2008 due to an average depletion rate increase of 21% and a 23% increase in production year-to-year. The increase in the average depletion rate contributed $28.3 million to the increase. The remaining $25.0 million increase in DD&A year-to-year is related to higher production in 2009. The DD&A rate increased to $5.38 per Mcfe for 2009 from $4.43 per Mcfe for 2008. We calculated DD&A rates for the first half of 2009 using the December 31, 2008 reserves. We calculated the DD&A rate for the second half of 2009 using an internally generated reserve report dated June 30, 2009, with a NYMEX gas price of $3.88 per MMbtu. The reserve estimates from the report as of June 30, 2009, resulted in a decrease in proved developed reserves from year end 2008, due primarily to a reduction in the price used for purposes of evaluating the reserves, from $5.71 per MMbtu at December 31, 2008 to $3.88 per MMbtu at June 30, 2009. As a result, the DD&A rate utilized for the second half of the year 2009, increased to $5.81 per Mcfe versus $4.91 per Mcfe in the first half of 2009. The higher DD&A rate of $5.81 mainly results from a decrease in our proved developed reserves as of June 30, 2009 due to the impact of lower prices on our traditional Cotton Valley and Travis Peak vertical reserves, which represented a majority of our proved developed reserves at June 30, 2009. Similarly, the higher rate for the second half of the year increased the DD&A rate for the entire year 2009 to $5.38 per Mcfe, a 21% increase from 2008.

While our internal, mid-year reserve reports were prepared in accordance with existing SEC guidelines, they should not be construed as a fully independent engineering reserve report similar to what we have used in the past and what we used at year end.

Impairment

We recorded impairment expense of $234.9 million on several fields for the year ended December 31, 2010, related primarily to a decreasing projected natural gas price environment resulting in the write down of the carrying values of certain non-core assets. In addition to lower commodity prices, the impairment was a result of our change in forward looking development plans, which will focus on the Eagle Ford Shale, core Haynesville Shale in North Louisiana and the Angelina River Trend of the Shelby Trough.

We recorded an impairment of $208.9 million in 2009 related to the Bethany Longstreet, Bethune/East Gates, Loco Bayou, Cotton South/Raintree and a collection of other fields as a result of the decrease in natural gas prices in 2009 from 2008 which lowered economical proved reserves. Proved and probable reserves were also lowered due to our strategic decision to decrease using vertical wellbores to develop our existing properties because this method was deemed no longer the most economic avenue to pursue. The impairment charge in 2009 was also driven by the removal of the previously scheduled vertical proved and probable drilling locations and was partially offset by the addition of horizontal undeveloped locations in fields where such locations were deemed appropriate.

We recorded an impairment of $28.6 million in 2008 related to assets located in non-core areas of Northwest Louisiana and East Texas.

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General and Administrative Expense

General and administrative (G&A) expense increased $3.0 million or 11% to $30.9 million in 2010 compared to $27.9 million in 2009. G&A expense in 2010 included compensation costs related to the resignation of an officer of the company. See Note 14 Resignation of Executive Officer to our consolidated financial statements in this report for more information. G&A expense for the year 2010 also includes 2009 bonuses approved and paid out in March 2010. Share based compensation expense, which is a non-cash item, amounted to $7.6 million in 2010 compared to $6.8 million in 2009. G&A on a per unit basis decreased to $0.92 per Mcfe from $0.94 per Mcfe as a result of the 13% increase in production volume in 2010 compared to 2009.

G&A expense increased $3.7 million or 15% to $27.9 million in 2009 compared to $24.3 million in 2008. The increase results primarily from higher compensation cost resulting from having a larger work force. We had 125 employees as of December 31, 2009 versus 114 employees as of December 31, 2008, an increase of 10%. G&A on a per unit basis decreased to $0.94 per Mcfe from $1.00 per Mcfe as a result of a 23% increase in production volumes in 2009 as compared to 2008. Share based compensation expense, which is a non-cash item, amounted to $6.8 million in 2009 compared to $5.5 million in 2008.

Other

Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC et al. On April 29, 2010 a state court in Caddo Parish, Louisiana, granted a judgment holding us solely responsible for the payment of $8.5 million in additional oil and gas lease bonus payments and related interest in an ongoing lawsuit involving the interpretation of a unique oil and gas lease provision. The lease provided for the payment of additional bonuses under certain circumstances in the event higher lease bonuses were paid by us, or our successors or assigns, within the surrounding area. Without our knowledge, one of the sub-lessees subject to the same lease paid substantially higher bonuses in the area. We believe that this ruling was improperly decided and, on July 8, 2010, filed a motion for a suspensive appeal. We satisfied the requirements for posting a suspensive appeal bond by depositing $8.5 million with Iberia Bank in Shreveport, Louisiana for the account of the Clerk of Caddo Parish Court, our portion of this deposit is carried in restricted cash on our Consolidated Balance Sheet. We accrued the full amount of $8.5 million as expense in the first quarter of 2010.

On July 9, 2010, the sub-lessee agreed to reimburse us for one half of any sums for which we may be cast in judgment in this lawsuit in any final non-appealable judgment, and further agreed to reimburse us for one half of the cash bond. We reduced our accrual by $4.2 million in the third quarter of 2010 and the remaining $4.3 million as of December 31, 2010 is reflected as Operating Expenses Other in the Consolidated Statement of Operations.

Other Income (Expense)

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Other Income (Expense):			
Interest expense	$ (37,179)	$ (26,148)	$ (22,410)
Interest income	117	458	1,682

Gain (loss) on derivatives not designated as hedges	55,275	47,115	51,547
Income tax benefit (expense)	85	67,311	(54,472)
Average funded borrowings adjusted for debt discount	379,582	268,000	244,401
Average funded borrowings	400,405	304,211	271,321

Interest Expense

Interest expense increased $11.1 million to $37.2 million for 2010 compared to $26.1 million for 2009 as a result of the higher average level of outstanding debt in the current year. The higher average level of debt is the

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result of the issuance of our 5% convertible senior notes in September 2009. Non-cash interest of $19.3 million is included in the $37.2 million interest expense reported in 2010. Non-cash interest of $12.2 million is included in the $26.1 million interest expense reported for the year 2009.

Interest expense increased $3.7 million to $26.1 million for 2009 compared to $22.4 million for 2008 as a result of the write off of deferred financing cost and the pre-payment premium on the second lien term loan ($0.8 million) in addition to the interest accrued on the 5% convertible senior notes issued in September, 2009. Interest expense in 2009 included non-cash charges of $12.2 million (mostly related to the amortization of debt discount on our convertible notes) while interest expense in 2008 included non-cash charges of $8.5 million.

Interest Income and Other

We invested the proceeds from the 5% convertible senior note offering in September 2009 and the net proceeds from our equity offering and the sale of assets, both in July 2008, in money market funds and time deposits with certain acceptable institutions, subject to our Short Term Investment Policy. We used the invested proceeds throughout 2010 and 2009 to fund our capital program. The income earned on these investments during 2010, 2009 and 2008 is reflected in the Interest income line. For more information on our Short Term Investment Policy, please see Liquidity Short Term Investments.

Gain on Derivatives Not Designated as Hedges

We produce and sell oil and natural gas into a market where selling prices are historically volatile. For example, on January 8, 2010 the Henry Hub natural gas spot price reached a high of $7.51 per MMbtu, but the price was down to $3.73 per MMBtu by September 2, 2010 and back up to $4.19 per MMBtu by December 30, 2010. We enter into swap contracts, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production.

Gain on derivatives not designated as hedges was $55.3 million for 2010. The gain includes a realized gain of $24.6 million on our natural gas derivatives and an unrealized gain of $30.7 million for the change in fair value of our natural gas and oil commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2009 as compared to December 31, 2010.

Gain on derivatives not designated as hedges was $47.1 million for 2009, which includes a gain of $47.8 million from our natural gas derivatives offset by a $0.7 million loss on our interest rate derivatives. The gain on our natural gas derivatives includes a realized gain of $98.0 million offset by a $50.2 million unrealized loss for the change in fair value of our natural gas commodity contracts. The unrealized loss resulted from the roll off of existing natural gas derivative contracts during 2009. The loss on interest rate hedges in 2009 includes a realized loss of $1.4 million offset by an unrealized gain of $0.7 million. Our interest rate derivative contracts expired in the first half of 2010.

Gain on derivatives not designated as hedges for 2008 was $51.5 million including a realized loss of $2.5 million and an unrealized gain of $54.0 million for the changes in fair value of our derivative contracts.

We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts when we do not designate these contracts as hedges.

Income Tax (Expense) Benefit

We recorded a small tax benefit of less than $0.1 million in 2010, which reflects the monetization of our alternative minimum tax credit. We otherwise recorded no income tax benefit for the year 2010. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of December 31, 2010.

Income tax benefit from continuing operations of $67.3 million for 2009 includes an increase to our valuation allowance of $54.3 million. Income tax expense was $54.5 million for the year ended December 31, 2008. In 2008, we realized a significant gain on the sale of assets related primarily to our sale of deep rights acreage to Chesapeake which helped generate income before taxes of $176.2 million for 2008. As a result of the significant gain generated by the sale, we released $15.3 million of our previously booked valuation allowance. The impact of this was to reduce income tax expense for 2008.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The Company s primary sources of cash during 2010 were cash flow from operating activities and proceeds from divestitures. We used cash primarily to fund our capital spending program, and pay preferred stock dividends. The Company s primary sources of cash during 2009 were cash flow from operating activities and the issuance of debt. In 2009, we used cash primarily to fund our capital spending program, retire debt and pay preferred stock dividends. The Company s primary sources of cash during 2008 were the issuance of equity securities, sale of assets and cash flow from operating activities. In 2008, the Company used cash primarily to fund our capital spending program and pay preferred stock dividends.

The Company has in place a $350 million Senior Credit Facility, entered into with a syndicate of United States and international lenders, and as of December 31, 2010, the Company had a $225 million borrowing base with no outstanding borrowings under its senior credit facility. On February 4, 2011, the Company entered into a Third Amendment to our Senior Credit Facility revising our interest coverage ratio from 3.0x to 2.5x to take into consideration additional non-cash interest recorded due to the adoption on January 1, 2009 of a new accounting standard related to our convertible notes. We were in compliance with existing covenants, as amended and the full amount of the borrowing base of the Senior Credit Facility was available for borrowing at December 31, 2010.

We continuously monitor our leverage position and coordinate our capital program with our expected cash flows and repayment of our projected debt. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:

- issuance of debt securities,
- sale of non-core assets,

bring in joint venture partners in core Haynesville and/or Eagle Ford Shale acreage,

availability under our Senior Credit Facility.

Our Senior Credit Facility matures on August 31, 2011. In addition, holders of our $175 million principal amount 3.25% Convertible Senior Notes Due 2026 have the right to require us to purchase some or all of such notes at par on December 1, 2011. Because the conversion price of those notes is substantially above recent trading price of our common stock, it is more likely than not that notes will be put to us for repurchase on such date. We expect to renew our credit facility and use borrowings from such renewed facility, additional borrowings or other sources of funding to repay any such notes that are required to be repurchased. Should we redeem the 2026 Notes, the maturity date under our Senior Credit Facility will extend to July 1, 2012.

The following section discusses significant sources and uses of cash for the three-year period ending December 31, 2010. Forward-looking information related to our liquidity and capital resources are discussed in *Outlook* that follows.

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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 senior credit facility. In the future, as we have done on several occasions over the last few years, we may also access public markets to issue additional debt and/or equity securities.

Primary sources of cash during 2010 were cash flow from operating activities and sale of assets.

Our primary sources of cash during 2009 were from the issuance of our 5% convertible senior notes of $218.5 million in September 2009, funds generated from operations and bank borrowings. Cash was used primarily to fund exploration and development expenditures. We made aggregate cash payments of $18 million for interest in 2010. The table below summarizes the sources of cash during 2010, 2009 and 2008:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	**2010**	**2009**	**Variance**	**2009**	**2008**	**Variance**
			(In thousands)			
Net Cash:						
Provided by operating activities	$ 100,432	$ 115,570	$ (15,138)	$ 115,570	$ 107,039	$ 8,531
Used in investing activities	(200,080)	(265,587)	65,507	(265,587)	(187,786)	(77,801)
Provided by (used) financing activities	(7,680)	127,585	(135,265)	127,585	223,847	(96,262)
Increase (decrease) in cash and cash equivalents	$ (107,328)	$ (22,432)	$ (84,896)	$ (22,432)	$ 143,100	$ (165,532)

At December 31, 2010, we had a working capital deficit of $199.5 million and long-term debt, net of debt discount, of $179.2 million. Our working capital deficit position is primarily due to our 3.25% Senior Convertible Notes due 2026 being considered current as of December 31, 2010. The holders of the notes have the right to require us to purchase all or a portion of their notes on December 1, 2011.

Cash Flows

Year ended December 31, 2010 Compared to Year Ended December 31, 2009

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 $100.4 million, a decrease of $15.1 million, or 13%, from $115.6 million in 2009. Our operating revenues increased 34% in 2010 with a 18% decrease in commodity prices and an increase in average daily production of 13% as compared to 2009. The cash flow decrease is also the result of receiving $24.6 million in natural gas derivative settlements in 2010 compared to having received $98.0 million for settlements of natural gas derivatives in 2009.

Investing activities. Net cash used in investing activities was $200.1 million for the year ended December 31, 2010, compared to $265.6 million for 2009. While we booked capital expenditures of approximately $283.7 million in 2010, we paid out cash amounts totaling $265.0 million in 2010, with the difference being attributed to approximately $30.0 million in drilling and completion costs which were accrued at December 31, 2010, non-cash asset retirement obligation additions of $1.3 million and geophysical and geological cost of $1.2 million offset by $13.8 million in drilling and completion cost accrued at December 31, 2009 and paid in 2010. In the fourth quarter of 2010, we incurred additional drilling and completion capital expenditures in excess of that which was budgeted from (1) acceleration of completion of Haynesville Shale wells that were scheduled for 2011; (2) incremental drilling and completion costs associated with longer laterals in our Eagle Ford Shale trend; and (3) reduced drilling cycles thereby incurring additional drilling capital expenditures as a result of drilling more wells. Net cash used in investing activities was offset by the receipt of $64.9 million of cash proceeds from the sale of fixed assets in 2010.

We conducted drilling and completion operations on 46 gross wells in 2010 compared to 45 gross wells in 2009. Of the $265.0 million cash spent this year, approximately $227.6 million was for drilling and completion activities (of which $13.8 million related to 2009 wells), $33.7 million was for leasehold acquisition, $0.6 million for facilities and infrastructure, $2.3 million for capital workovers, and $0.8 million for furniture, fixtures and equipment. Of the $265.8 million spent in 2009, approximately $239.5 million was for drilling and completion activities (of which $28.3 million related to 2008 wells), $15.9 million was for leasehold acquisition, $4.1 million for facilities and infrastructure, $3.4 million for capital workovers, $1.9 million on geological and geophysical and $1.0 million for furniture, fixtures and equipment

Financing activities. Net cash used in financing activities was $7.7 million for 2010, a decrease of $135.3 million from net cash provided by financing activities of $127.6 million in 2009. In September 2009, we received $218.5 million from the offering of our 5% convertible senior notes due 2029. With the proceeds from the offering, we paid $8.8 million in offering cost, paid off our $75.0 million second lien term loan and paid off the $5.0 million balance on our senior credit facility. We had zero borrowings outstanding under our Senior Credit Facility as of December 31, 2010.

Year ended December 31, 2009 Compared to Year Ended December 31, 2008

Operating activities. Net cash provided by operating activities for 2009 was $115.6 million, an increase of $8.6 million, or 8%, from $107.0 million in 2008. Our operating revenues decreased 49% in 2009 with a 58% decrease in commodity prices offset by an increase in average daily production of 24% as compared to 2008. The favorable cash flow increase is also the result of receiving $98.0 million in natural gas derivative settlements in 2009 compared to having expended $1.8 million for settlements of natural gas derivatives in 2008.

Investing activities. Net cash used in investing activities was $265.6 million for the year ended December 31, 2009, compared to $187.8 million for 2008 (which was reduced in 2008 by the $175.1 million in asset sales mentioned previously). While we booked capital expenditures of approximately $237.5 million in 2009, we paid out cash amounts totaling $265.8 million in 2009, with the difference being attributed to approximately $28.3 million in drilling and completion costs which were accrued at December 31, 2008 but not paid until early in fiscal year 2009. We conducted drilling and completion operations on 45 gross wells in 2009 compared to 126 gross wells in 2008, a decrease of 64%. Of the $265.8 million spent this year, approximately $239.5 million was for drilling and completion activities (of which $28.3 million related to 2008 wells), $15.9 million was for leasehold acquisition, $4.1 million for facilities and infrastructure, $3.4 million for capital workovers, $1.9 million on geological and geophysical and $1.0 million for furniture, fixtures and equipment. Of the $362.8 million invested in 2008, we spent $328.8 million for drilling and completion activities, $28.6 million for leasehold acquisition, $4.2 million for facilities and infrastructure and $1.2 million for furniture, fixtures and equipment.

Financing activities. Net cash provided by financing activities was $127.6 million for 2009, a decrease of $96.2 million from $223.8 million in 2008.

In 2008, we borrowed $75.0 million on our Second Lien Term Loan and used $53.5 million of the borrowings to pay-off the balance on our senior credit facility. We also received net proceeds of $191.3 million from an equity offering. We used these proceeds to pay the full outstanding balance on our existing bank credit facility. We had no borrowings outstanding under our Senior Credit Facility as of December 31, 2008.

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Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $350 million. The Senior Credit Facility matures on August 31, 2011. The Senior Credit Facility can be further extended to July 1, 2012 upon receipt of proceeds from a refinancing sufficient to prepay the 3.25% convertible senior notes due 2026, which the holders have the option to put to the Company on December 1, 2011. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of, the borrowing base. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50%, or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on April 1 and October 1 beginning on October 1, 2009. In connection with the offering of the $218.5 million 5% convertible senior notes due 2029, we entered into an amendment of our Senior Credit Facility to permit the issuance of the notes and required payments made on the notes thereafter and to exclude up to $175 million of our 3.25% convertible senior notes due 2026 or our 5% convertible senior notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. As of December 31, 2010, we had no amounts outstanding under the credit facility which has a borrowing base of $225.0 million.

Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used, but not defined, here have the meanings assigned to them in the Senior Credit Facility. The primary financial covenants include:

Current Ratio of 1.0/1.0;

Interest Coverage Ratio of not less than 2.5/1.0 for the trailing four quarters; and

Total Debt no greater than 3.0 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 include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Up to $175 million of our convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

On February 4, 2011, we entered into a third amendment to our senior credit facility revising our interest coverage ratio from 3.0x to 2.5x to take into consideration additional non-cash interest recorded due to the adoption on January 1, 2009 of a new accounting standard related to our convertible notes. We are in compliance with all the financial covenants as amended of the Senior Credit Facility as of December 31, 2010.

Second Lien Term Loan

On September 29, 2009, we fully paid off the second lien term loan with proceeds received from the issuance of our 5% convertible senior notes due 2029.

3.25% Convertible Senior Notes Due 2026

In December 2006, we sold $175.0 million of 3.25% convertible senior notes (the 2026 Notes) due in December 2026. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes accrue interest at a rate of 3.25% annually, and interest is paid semi-annually on June 1 and December 1.

On or after December 1, 2011, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of December 1, 2011, 2016 and 2021.

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Interest expense relating to the contractual interest rate and amortization of both financing cost and debt discount relating to these notes for the years ended December 31, 2010, 2009 and 2008 was $14.5 million, $13.9 million and $13.3 million, respectively. The effective interest rate on the liability component of the notes was 9% for each of the years 2010, 2009 and 2008.

5% Convertible Senior Notes Due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes (the 2029 Notes) due in October 2029. The notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The notes accrue interest at a rate of 5% annually, and interest is paid semi-annually in arrears on April 1 and October 1 of each year, beginning in 2010. Interest began accruing on the notes on September 28, 2009. On or after October 1, 2014, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of October 1, 2014, 2019 and 2024. Interest expense recognized relating to the contractual interest rate and amortization of both financing cost and debt discount for the year ended December 31, 2010 was $20.0million. The effective rate on the liability component of the notes was 11.2% in the year 2010.

For additional information on our debt instruments, see *Note 4 Debt* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Equity Offering

On July 14, 2008, we closed the public offering of 3,121,300 shares of our common stock at a price of $64.00 per share. Net proceeds from the offering were approximately $191.3 million after deducting the underwriters discount and estimated offering expenses. We used approximately $96.0 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility. We used the remaining net proceeds for general corporate purposes, including funding a portion of our remaining 2008 drilling program, other capital expenditures and working capital requirements.

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.

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.

For additional information on our debt instruments, see *Note 7 Stockholder s Equity* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Outlook

The Company s capital budgeting process is ongoing. Our total budget for capital expenditures for 2011 is expected to be $235 million, exclusive of acquisitions other than leases acreage additions in our core areas. We expect capital spending by area to be approximately 62% for Eagle Ford Shale Trend, 22% for Haynesville Shale Trend, 10% for CVTS and 6% for Other. The Company s primary emphasis will be on managing near-term growth opportunities. We believe that our expected level of operating cash flows, cash on hand as of December 31, 2010, and our borrowing base will be sufficient to fund our projected operational and capital

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programs for 2011. However, if capital expenditures exceed operating cash flow and cash on hand, funds would likely be supplemented as needed through short-term borrowings under our fully available $225.0 million senior credit facility or through the issuance of debt or equity.

We will operate approximately 85% of wells drilled as part of our 2011 planned capital expenditures. Additionally, we operate over 67% of our proved reserves and 52% of our acreage is held by production. We have no drilling commitments and the ability to go non-consent on all wells proposed by partners.

In addition, to support 2011 and 2012 cash flows, we entered into strategic derivative positions as of January 1, 2011, on approximately 41% of our anticipated natural gas sales volumes and approximately 42% of our anticipated oil and condensate sales volumes for 2011. In addition, the Company has entered into commodity-price-risk management derivative positions for the year 2012. See *Note 8 Derivative Activities* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

We may choose to refinance certain portions of our short-term borrowings by issuing long-term debt or equity, or both. We continuously monitor our leverage position and coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives as needed, including property divestitures or borrowings under our senior credit facility and the issuance of debt or equity securities. We are currently considering options to refinance the 3.25% Convertible Senior Notes due 2026. Included in those options are the issuance of debt securities or bringing in joint venture partners in core Haynesville and/or Eagle Ford Shale acreage. To the extent additional borrowings were not available to us, we believe we could satisfy the obligation of the 2026 Notes through a combination of our Senior Credit Facility availability and cash flow from operations while reducing our 2011 capital expenditures.

Credit Risks

Our exposure to non-payment or non-performance by our customers and counterparties presents a credit risk. Generally, non-payment or non-performance results from a customer s or counterparty s inability to satisfy obligations. We monitor the creditworthiness of our customers and counterparties and established credit limits according to our credit policies and guidelines. We have the ability to require cash collateral as well as letters of credit from our financial counterparties to mitigate our exposure above assigned credit thresholds. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties.

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, 2010 (in thousands). In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2010 reflects accrued interest on our bank debt of $3.2 million payable in the first half of 2011. 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**	**2011**	**2012**	**2013**	**2014**	**2015 and After**

Contractual Obligations							
Long term debt (1)	4	$ 393,500	$ 175,000	$	$	$ 218,500	$
Interest on convertible senior notes	4	46,182	16,138	10,925	10,925	8,194	
Office space leases	10	9,246	1,042	1,044	1,142	1,104	4,914
Office equipment leases	10	793	496	114	100	56	27
Drilling rigs & operations contracts	10	27,179	18,744	7,702	583	150	
Total contractual obligations (2)		$ 476,900	$ 211,420	$ 19,785	$ 12,750	$ 228,004	$ 4,941

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(1) The $175.0 million 3.25% Convertible Senior Notes due 2026 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. The $218.5 million 5.0% Convertible Senior Notes due 2029 have a provision by which on or after October 1, 2014, the Company may redeem all or a portion of the notes for cash, and the investors may require the Company to repurchase the notes on each of October 1, 2014, 2019 and 2024.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $16.1 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3-Asset Retirement Obligation in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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 Accounting Policies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Proved Oil and Natural Gas Reserves

Proved reserves are defined by the SEC as those quantities of oil and gas which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well. 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.

While the estimates of our proved reserves at December 31, 2010 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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 new 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.

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Fair Value Measurement

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We carry our derivative instruments at fair value and measure their fair value by applying the income approach, using level 2 inputs based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our credit worthiness or that of our counterparties. We carry our oil and gas properties held for use and for sale at historical cost. We use level 3 inputs which are unobservable data such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices to determine the fair value of our oil and gas properties in determining impairment. We carry cash and cash equivalents, account receivables and payables at carrying value which represent fair value because of the short-term nature of these instruments.

Impairment of Properties

We monitor our long-lived assets recorded in oil and gas properties in the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value. 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 in order to ensure that they are presented at fair value. 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.

Accounting for uncertainty in income taxes 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. See Note 1 Description of Business and Accounting Policies-Income Taxes and Note 6 Income Taxes to our consolidated financial statements.

Share-Based Compensation Plans

For all new, modified and unvested share-based payment transactions with employees, we measure the fair value on the grant date and recognize it 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

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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. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

New Accounting Pronouncements

See Note 1 Description of Business and 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***

The Company s primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. The Company s risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments utilized by the Company include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments utilized by the Company may vary from year to year and is governed by risk-management policies with levels of authority delegated by the Board of Directors. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding the Company s accounting policies and additional information related to the Company s derivative and financial instruments, see *Note 1 Summary of Significant Accounting Policies, Note 8 Derivative Instruments* and *Note 4 Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Commodity Price Risk

The Company s most significant market risk relates to fluctuations in natural gas and crude oil prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. In addition, a non-cash write-down of the Company s oil and gas properties may be required if future commodity prices experience a sustained and significant decline. Below is a sensitivity analysis of the Company s commodity-price-related derivative instruments.

The Company had derivative instruments in place to reduce the price risk associated with future equity production of approximately 29.2 Bcf of natural gas and 0.9 MMBbls of crude oil as of December 31, 2010. At December 31, 2010, the Company had a net asset derivative position of $35.8 million related to these derivative instruments. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $14.4 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $9.8 million. However, a gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

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Interest Rate Risk

As of December 31, 2010, we had no outstanding variable-rate debt and $393.5 million of fixed-rate debt. To the extent we incur borrowings under our senior credit facility; our exposure to variable interest rates will increase. In the past, we have entered into interest rate swaps to help reduce our exposure to interest rate risk, and we may seek to do so in the future if we deem appropriate.

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

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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, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on page 53.

Management of Goodrich Petroleum Corporation

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited Goodrich Petroleum Corporation and Subsidiary internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Goodrich Petroleum Corporation and Subsidiary 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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Goodrich Petroleum Corporation and subsidiary maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2010 consolidated financial statements of Goodrich Petroleum Corporation and subsidiary and our report dated February 21, 2011, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 21, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and subsidiary (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, cash flows, and stockholders equity, for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Goodrich Petroleum Corporation and subsidiary at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 15 to the consolidated financial statements, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements as of December 31, 2009.

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, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 21, 2011

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEET

(In Thousands)

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 17,788	$ 125,116
Restricted cash	4,232	
Accounts receivable, trade and other, net of allowance	9,231	7,944
Income taxes receivable	4,335	15,438
Accrued oil and gas revenue	14,920	17,206
Fair value of oil and gas derivatives	24,467	5,403
Inventory	7,831	662
Prepaid expenses and other	3,045	1,609
Total current assets	85,849	173,378
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,217,891	1,339,462
Furniture, fixtures and equipment	4,962	3,985
	1,222,853	1,343,447
Less: Accumulated depletion, depreciation and amortization	(685,110)	(669,463)
Net property and equipment	537,743	673,984
Fair value of oil and gas derivatives	15,732	
Deferred tax asset	19,695	4,700
Deferred financing cost	5,558	8,212
TOTAL ASSETS	$ 664,577	$ 860,274
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 47,106	$ 35,079
Accrued liabilities	47,105	25,308
Accrued abandonment costs	4,392	4,574
Deferred tax liability current	19,695	4,700
Fair value of interest rate derivatives		1,087
Current portion of debt	167,086	
Total current liabilities	285,384	70,748
LONG-TERM DEBT	179,171	330,147
Accrued abandonment costs	11,683	13,716
Fair value of oil and gas derivatives	4,367	278
Total liabilities	480,605	414,889

Commitments and contingencies (See Note 9)		
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 shares authorized, issued and outstanding 37,685,378 and 37,452,023 shares, respectively	7,212	7,166
Treasury stock (12,377 and 19,915 shares, respectively)	(196)	(411)
Additional paid in capital	643,828	637,335
Retained earnings (accumulated deficit)	(469,122)	(200,955)
Total stockholders equity	183,972	445,385
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 664,577	$ 860,274

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2010	**2009**	**2008**
REVENUES:			
Oil and gas revenues	$ 148,031	$ 110,784	$ 215,369
Other	302	(358)	682
	148,333	110,426	216,051
OPERATING EXPENSES:			
Lease operating expense	26,306	30,188	31,950
Production and other taxes	3,627	4,317	7,542
Transportation	9,856	9,459	8,645
Depreciation, depletion and amortization	105,913	160,361	107,123
Exploration	10,152	9,292	8,404
Impairment of oil and gas properties	234,887	208,905	28,582
General and administrative	30,918	27,923	24,254
Loss (gain) on sale of assets	2,824	(297)	(145,876)
Other	4,268		
	428,751	450,148	70,624
Operating income (loss)	(280,418)	(339,722)	145,427
OTHER INCOME (EXPENSE):			
Interest expense	(37,179)	(26,148)	(22,410)
Interest income and other	117	458	1,682
Gain on derivatives not designated as hedges	55,275	47,115	51,547
	18,213	21,425	30,819
Income (loss) before income taxes	(262,205)	(318,297)	176,246
Income tax benefit (expense)	85	67,311	(54,472)
Net income (loss)	(262,120)	(250,986)	121,774
Preferred stock dividends	6,047	6,047	6,047
Net income (loss) applicable to common stock	$ (268,167)	$ (257,033)	$ 115,727
PER COMMON SHARE			
Net income (loss) applicable to common stock basic	$ (7.47)	$ (7.17)	$ 3.42
Net income (loss) applicable to common stock diluted	$ (7.47)	$ (7.17)	$ 3.23
Weighted average common shares outstanding basic	35,921	35,866	33,806
Weighted average common shares outstanding diluted	35,921	35,866	40,397

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31,		
	2010	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (262,120)	$ (250,986)	$ 121,774
Adjustments to reconcile net income (loss) to net cash provided by operating activities Depletion, depreciation, and amortization	105,913	160,361	107,123
Unrealized (gain) loss on derivatives not designated for hedge accounting	(31,794)	49,434	(53,995)
Deferred income taxes		(51,845)	34,835
Exploration costs		219	312
Amortization of leasehold costs	5,963	4,927	5,838
Impairment of oil and gas properties	234,887	208,905	29,751
Share based compensation (non-cash)	7,554	6,751	5,493
Loss (gain) on sale of assets	2,824	(297)	(145,876)
Amortization of finance cost and debt discount	19,256	12,221	8,465
Other non-cash items		282	53
Change in assets and liabilities:			
Restricted cash	(4,232)		
Accounts receivable, trade and other, net of allowance	(343)	(925)	1,467
Inventory	(7,169)	102	(1,376)
Income taxes receivable		(15,438)	
Deferred revenue			(12,500)
Accrued oil and gas revenue	403	(1,611)	(3,395)
Accounts payable	14,571	(6,338)	4,495
Income taxes payable	11,103	(1,320)	1,383
Accrued liabilities	4,901	976	3,184
Prepaid expenses and other	(1,285)	152	8
Net cash provided by operating activities	100,432	115,570	107,039
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(264,967)	(265,825)	(362,847)
Proceeds from sale of assets	64,887	238	175,061
Net cash used in investing activities	(200,080)	(265,587)	(187,786)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from convertible note offering		218,500	
Principal payments of bank borrowings	(54,500)	(80,000)	(155,500)
Proceeds from bank borrowings	54,500	5,000	190,000
Exercise of stock options and warrants	10	26	2,819
Deferred financing costs	(492)	(8,755)	(1,498)
Preferred stock dividends	(6,047)	(6,047)	(6,047)
Net proceeds from common stock offering			191,340
Excess tax benefit from stock based compensation			3,222

Other	(1,151)	(1,139)	(489)
Net cash provided by (used in) financing activities	(7,680)	127,585	223,847
Increase (decrease) in cash and cash equivalents	(107,328)	(22,432)	143,100
Cash and cash equivalents, beginning of period	125,116	147,548	4,448
Cash and cash equivalents, end of period	$ 17,788	$ 125,116	$ 147,548
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$ 18,014	$ 12,446	$ 12,981
Cash paid during the year for taxes	$	$ 1,352	$ 14,778

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In Thousands)

	Preferred Stock Shares	Preferred Stock Value	Common Stock Shares	Common Stock Value	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Value	Retained Earnings/ (Deficit)	Total Stockholder s Equity
Balance at January 1, 2008	2,250	$ 2,250	34,821	$ 6,340	$ 364,262	(16)	$ (422)	$ (59,649)	312,781
Net income								121,774	121,774
Offering of common stock			4,030	806	224,405				225,211
Employee stock plans			194	39	10,879				10,918
Director stock grants			16	3	579				582
Shares issued pursuant to share lending agreement			(1,498)						
Repurchases of stock						(16)	(485)		(485)
Retirement of stock						22	614		614
Dividends								(6,047)	(6,047)
Balance at December 31, 2008	2,250	2,250	37,563	7,188	600,125	(10)	(293)	56,078	665,348
Net loss								(250,986)	(250,986)
Capped call option redemption			(266)	(53)					(53)
Equity portion of convertible notes					31,165				31,165
Employee stock plans			139	28	5,991				6,019
Director stock grants			16	3	54				57
Repurchases of stock						(44)	(1,132)		(1,132)
Retirement of stock						34	1,014		1,014
Dividends								(6,047)	(6,047)
Balance at December 31, 2009	2,250	2,250	37,452	7,166	637,335	(20)	(411)	(200,955)	445,385
Net loss								(262,120)	(262,120)
Employee stock plans			282	52	7,502				7,554
Employee stock option exercise				1	9				10
Director stock grants			24	5	301				306
Repurchases of stock				3	(1)	(65)	(1,113)		(1,111)
Retirement of stock			(73)	(15)	(1,313)	73	1,328		
Other					(5)				(5)
Dividends								(6,047)	(6,047)
Balance at December 31, 2010	2,250	$ 2,250	37,685	$ 7,212	$ 643,828	(12)	$ (196)	$ (469,122)	$ 183,972

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Accounting Policies

Goodrich Petroleum Corporation (together with its subsidiary, we, our, or the Company) is an independent oil and gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in Northwest Louisiana, East Texas and South Texas.

Principles of Consolidation The consolidated financial statements of Goodrich Petroleum Corporation (Goodrich, the Company or we) included in this Annual Report on Form 10-K have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC) and in accordance with accounting principles generally accepted in the United States (US GAAP). The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiary. Intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Certain data in prior periods financial statements have been adjusted to conform to the presentation of the current period. We have evaluated subsequent events through the date of this filing.

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 US GAAP.

Presentation Change The Consolidated Statement of Operations includes a category of expense titled Interest income and other which includes immaterial effects of discontinued operations from the prior periods. The net effect of discontinued operations is added to this account for the comparative years of 2009 and 2008.

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 Restricted cash consists of cash held in escrow totaling $4.2 million for the posting of the suspensive appeal bond relating to the Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC litigation. See Note 9.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Many of our receivables are from a limited number of purchasers. Accordingly, accounts receivable from such purchases could be significant. Generally, our natural gas and crude oil receivables are collected within thirty to sixty days of production. We also have receivables from joint interest owners of properties we operate. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of each of December 31, 2010 and 2009, our allowance for doubtful accounts was immaterial.

Inventory Inventory consists of casing and tubulars that are expected to be used in our capital drilling program and oil in storage tanks. Inventory is carried on the Balance Sheet at the lower of cost or market.

Property and Equipment We follow the successful efforts method of accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Exploration Exploration expenditures, including geological and geophysical costs, delay rentals and exploratory dry hole costs are expensed as incurred. Costs of drilling exploratory wells are initially capitalized pending determination of whether proved reserves can be attributed to the discovery. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are expensed. Development costs are capitalized, including the costs of unsuccessful development wells.

Fair Value Measurement Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We carry our derivative instruments at fair value and measure their fair value by applying the income approach, using level 2 inputs based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties. We carry our oil and gas properties held for use and for sale at historical cost. We use level 3 inputs which are unobservable data such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices to determine the fair value of our oil and gas properties in determining impairment. We carry cash and cash equivalents, account receivables and payables at carrying value which represent fair value because of the short-term nature of these instruments.

Impairment Proved oil and gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future net cash flows are calculated based on estimated future oil and gas sales revenues less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property s carrying amount over its estimated fair value based on estimated discounted future cash flows. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We perform this comparison using estimates of future commodity prices and our estimates of proved and probable reserves and recent market transactions. For the years ended December 31, 2010, 2009 and 2008, we recorded impairments of $234.9 million, $208.9 million and $28.6 million, respectively. See Note 13.

Depreciation Depreciation and depletion of producing oil and gas properties is calculated using the units-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs.

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in operating income. Depreciation of furniture, fixtures and equipment, consisting of office furniture, computer hardware and software and leasehold improvements, is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

Asset Retirement Obligations We follow the accounting standard related to accounting for asset retirement obligations. These obligations relate to the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. 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. Accretion expense is included in depreciation, depletion and amortization on our consolidated statement of operations.

Revenue Recognition Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

interest with other producers are recognized using the entitlements method. We record a liability or an asset for natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At December 31, 2010 and 2009 the net liability for gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

Derivative Instruments 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. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. We have not designated any of our derivative contracts as hedges accordingly; changes in fair value are reflected in earnings.

Income Taxes We account for income taxes, as required, 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.

We recognize, as required, the financial statement benefit of an uncertain 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 to 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 to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive stock options and restricted stock calculated using the Treasury Stock method and the potential dilutive effect of the conversion of shares associated with Convertible Preferred Stock and Convertible Notes.

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, when 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 the top two purchasers accounted for 29% and 17% of oil and gas revenues for the year ended December 31, 2010. Revenues from the top three purchasers accounted for 32%, 19% and 10% of oil and gas revenues for the year ended December 31, 2009. Revenues from the top three purchasers accounted for 33%, 20% and 9% of oil and gas revenues for the year ended December 31, 2008.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Share-Based Compensation We account for our share-based transactions using fair value and recognized compensation expense over the requisite service period. The fair value of each option award is estimated using a Black-Scholes option valuation model with various assumptions based on our estimates. Our assumptions include 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. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

New Accounting Pronouncements

Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing. In October 2009, the Financial Accounting Standards Board (FASB) issued guidance on accounting for own-share lending arrangements in contemplation of convertible debt issuance. The standard requires that such share-lending arrangement be measured at fair value at the date of issuance and recognized as an issuance cost with an offset to paid-in-capital and the loaned shares be excluded in the computation of basic and diluted earnings per share. The issuance cost is required to be amortized as interest expense over the life of the financing arrangement. The standard also requires additional disclosures including a description and the terms of the arrangement and the reason for entering into the arrangement. Retrospective application is required for all arrangements outstanding as of the beginning of the fiscal years beginning on or after December 15, 2009. The impact of the new guidance on our financial statements, as it relates to the shares outstanding under the share lending agreement (the Share Lending Agreement) that we entered into in connection with the December 2006 issuance of our 3.25% Convertible Senior Notes due 2026, was evaluated and considered immaterial.

Fair Value Measurements. In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. This guidance was adopted on January 1, 2010 for Level 1 and Level 2 fair value measurements and did not impact the Company s operating results, financial position, cash flows or disclosures.

NOTE 2 Share-Based Compensation Plans

Overview

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan provides for grants to employees and non-employee directors. 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, 2010, a total of 507,983 shares were available for future grants under the 2006 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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2006 Plan is also intended to enhance the ability of the Company and its Subsidiary 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.

We measure the cost of stock based compensation granted, including stock options and restricted stock, based on the fair value of the award as of the grant date, net of estimated forfeitures. Awards granted are valued at fair value and recognized on a straight-line basis over the service periods (or the vesting periods) of each award. We estimate forfeiture rates for all unvested awards based on our historical experience.

Total share-based compensation of $8.1 million, $7.4 million and $5.9 million for the years ended December 31, 2010, 2009 and 2008, respectively, has been recognized as a component of general and administrative expenses in the Consolidated Statement of Operations. The total income tax benefit associated with our share-based compensation recognized in our Consolidated Statement of Operations was $3.2 million for the year ended December 31, 2008.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Pretax stock option expense	$ 5,944	$ 1,428	$ 2,181
Pretax restricted stock expense	1,609	5,323	3,312
Pretax director stock expense	502	608	440
Total pretax share-based compensation:	$ 8,055	$ 7,359	$ 5,933

Stock Options

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.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Option activity under our stock option plans as of December 31, 2010, and changes during the year ended December 31, 2010 were as follows:

	Shares	Weighted Average Exercise Price	Remaining Contractual Term (years)	Aggregate Intrinsic Value (thousands)
Outstanding at January 1, 2010	947,634	$ 21.39	5.51	$ 2,804
Granted				
Exercised	(2,000)	4.88		$ 24
Forfeited	(10,000)	21.59		
Outstanding at December 31, 2010	935,634	$ 21.42	4.97	$ 338
Exercisable at December 31, 2010	796,134	$ 21.40	4.60	$ 338

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 2010 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, 2010. 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 years ended December 31, 2010, 2009, and 2008 was less than $0.1 million, $0.2 million and $6.2 million, respectively. During 2010, 2009 and 2008, $1.6 million, $1.4 million and $2.2 million, respectively, were charged to General and Administrative (G&A) expense related to stock options.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2010	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2010	Weighted Average Exercise Price
$4.11 to $5.85	12,000	1.40	$ 4.94	12,000	$ 4.94
$16.46 and $19.78	307,300	4.11	18.08	307,300	18.08
$21.59 to $27.81	616,334	5.47	23.41	476,834	23.95
	935,634	4.97	$ 21.42	796,134	$ 21.40

During 2008 we granted 162,000 stock options under the plan, valued at $1.7 million at the time of issuance. No options were granted in 2009. During 2010 we modified 60,000 stock options under the plan valued at an aggregate of $0.4 million. The estimated fair value of the options modified during 2010 and prior years was calculated using a Black-Scholes Merton option pricing model (Black-Scholes).

The following schedule reflects the various assumptions included in the Black-Scholes model as it relates to the valuation of our options of the options modified/granted in 2010 and 2008:

	2010	2008
Risk-free interest rate (1)	2.55%	3.52%
Expected volatility (2)	64%	53%
Expected dividend yield (3)	0%	0%
Expected term (4)	6	5

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Risk-free interest rate is based on a zero-coupon U.S. government instrument over the expected term.
(2) Expected volatility is based on the weighted average historical volatility of our common stock.
(3) Expected dividend yield we do not pay dividends on our common stock.
(4) Expected term we use the midpoint of the vesting period and the life of the grant to estimate employee option exercise timing.

As of December 31, 2010, $0.8 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted average period of approximately 4.97 years.

Restricted Stock

In 2003, we began granting a series of restricted stock awards. Restricted stock awarded under the 2006 Plan typically has a vesting period of three years. During the vesting period, ownership of the shares cannot be transferred and the shares are subject to forfeiture if employment ends before the end of the vesting period. Certain restricted stock awards provide for accelerated vesting. Restricted shares are not considered to be currently issued and outstanding until the restrictions lapse and/or they vest.

During 2010, 2009 and 2008, we granted 471,845, 343,749 and 437,048 shares of our common stock under the plan, valued at $7.4 million, $7.8 million and $11.4 million, respectively, at the time of issuance. During 2010, 2009 and 2008, $6.0 million, $5.3 million and $3.3 million, respectively, were charged to G&A expense related to the restricted share awards. The fair value of restricted stock vested during 2010, 2009 and 2008 was $6.1 million, $4.9 million and $2.1 million, respectively.

Restricted stock activity under our plan for the year ended December 31, 2010, and changes during the year then ended were as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
Unvested at January 1, 2010	623,586	$ 24.09	$ 15,023,854
Vested	(260,567)	23.55	(6,137,346)
Granted	471,845	15.75	7,432,220
Forfeited	(87,034)	23.45	(2,040,571)
Unvested at December 31, 2010	747,830	$ 19.09	$ 14,278,157

As of December 31, 2010, $12.7 million of total unrecognized compensation cost related to restricted stock is expected to be recognized over a weighted average period of approximately 2.3 years.

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NOTE 3 Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2010 and 2009 is as follows (in thousands):

	December 31,	
	2010	2009
Beginning balance	$ 18,290	$ 13,804
Liabilities incurred	76	352
Revisions in estimated liabilities	1,187	3,299
Liabilities settled	(175)	
Accretion expense	1,507	891
Dispositions	(4,810)	(56)
Ending balance	$ 16,075	$ 18,290
Current liability	$ 4,392	$ 4,574
Long term liability	$ 11,683	$ 13,716

During 2010, we determined that the expected productive lives of many of our wells had decreased relative to the 2009 estimate, while the plug and abandon costs remained relatively flat with only slight increases. As a result, we revised our previously estimated asset retirement obligation by a discounted $1.2 million.

NOTE 4 Debt

Debt consisted of the following balances (in thousands):

	December 31,	
	2010	2009
Senior Credit Facility	$	$
3.25% Convertible Senior Notes due 2026	175,000	175,000
Debt discount on 3.25% convertible senior notes	(7,914)	(15,915)
5.0% Convertible Senior Notes due 2029	218,500	218,500

Debt discount of 5.0% Convertible Senior Notes	(39,329)	(47,438)
Total debt	$ 346,257	$ 330,147
Current portion of debt	$ 167,086	$
Long term debt	$ 179,171	$ 330,147

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $350 million subject to a borrowing base calculation. The Senior Credit Facility matures on August 31, 2011. The Senior Credit Facility can be further extended to July 1, 2012 upon receipt of proceeds from a refinancing sufficient to prepay the 3.25% convertible senior notes due 2026. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of, the borrowing base. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50%, or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization.

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Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on April 1 and October 1 beginning on October 1, 2009. In connection with the offering of the $218.5 million 5% convertible senior notes due 2029, we entered into an amendment of our Senior Credit Facility to permit the issuance of the notes and required payments made on the notes thereafter and to exclude up to $175 million of our 3.25% convertible senior notes due 2026 or our 5% convertible senior notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. We currently have no outstanding debt under the credit facility with a borrowing base of $225 million. Since the 3.25% convertible notes due 2026 are outstanding any borrowings under the Senior Credit Facility will be classified as a current liability.

Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used, but not defined here, have the meanings assigned to them in the Senior Credit Facility. The primary financial covenants include:

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of not less than 2.5/1.0 for the trailing four quarters; and
- Total Debt no greater than 3.0 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 include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Up to $175.0 million of our convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

On February 4, 2011, we entered into a third amendment to our senior credit facility revising our interest coverage ratio from 3.0x to 2.5x to take into consideration additional non-cash interest recorded due to the adoption on January 1, 2009, of a new accounting standard related to our convertible notes.

We were in compliance with all the financial covenants as amended of the Senior Credit Facility as of December 31, 2010.

3.25% Convertible Senior Notes Due 2026

In December 2006, we sold $175.0 million of 3.25% convertible senior notes (the 2026 Notes) due in December 2026. The 2026 Notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The 2026 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2026 Notes accrue interest at a rate of 3.25% annually, and interest is paid semi-annually on June 1 and December 1. Interest payments on the notes began on June 1, 2007.

Before December 1, 2011, we may not redeem the notes. On or after December 1, 2011, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of December 1, 2011, 2016 and 2021. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

Investors may convert their notes at their option at any time prior to the close of business on the second business day immediately preceding the maturity date under the following circumstances: (1) during any fiscal quarter (and only during such fiscal quarter) commencing after March 31, 2007, if the last reported sale price of our common stock is greater than or equal to 135% of the base conversion price of the notes (as defined in this

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offering memorandum) for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter; (2) prior to December 2, 2011, during the five business-day period after any 10 consecutive trading-day period (the measurement period) in which the trading price of $1,000 principal amount of notes for each trading day in the measurement period was less than 95% of the product of the last reported sale price of our common stock and the applicable conversion rate on such trading day; (3) if the notes have been called for redemption; or (4) upon the occurrence of specified corporate transactions described in this offering memorandum. Investors may also convert their notes at their option at any time beginning on November 1, 2026, and ending at the close of business on the second business day immediately preceding the maturity date.

The notes are convertible into shares of our common stock at a rate equal to the sum of:

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

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

We separately account for the liability and equity components of the 2026 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. On January 1, 2009, according to accounting standards related to accounting for debt instruments that may be settled in cash upon conversion, we recorded a beginning of period debt discount balance of $23.3 million which represents the unamortized debt discount of the original retrospective debt discount of approximately $37.0 million and an equity component net of tax of $23.9 million. As of December 31, 2010, the $175.0 million 2026 Notes were carried on the balance sheet at $167 million with a debt discount balance of $7.9 million. As of December 31, 2009, the $175.0 million of 2026 Notes were carried on the balance sheet at $159.1 million with a debt discount balance of $15.9 million. The remaining amount of debt discount as of December 31, 2010 will be amortized using the effective interest rate method based upon an original five year term through December 1, 2011.

Interest expense relating to the contractual interest rate and amortization of both financing cost and debt discount relating to the 2026 Notes for the years ended December 31, 2010, 2009 and 2008 was $14.5 million, $13.9 million and $13.3 million, respectively. The effective interest rate on the liability component of the 2026 Notes was 9% for each of the years 2010, 2009 and 2008.

The investors may require us to repurchase the 2026 Notes on December 1, 2011. Consequently as of December 1, 2010 the 2026 notes are classified as a current liability.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes due in October 2029 (the 2029 Notes). The notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The notes are 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 5% annually, and interest is paid semi-annually in arrears on April 1 and October 1 of each year, beginning in 2010. Interest began accruing on the notes on September 28, 2009.

Before October 1, 2014, we may not redeem the notes. On or after October 1, 2014, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of October 1, 2014, 2019 and 2024. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

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Investors may convert their notes at their option at any time prior to the close of business on the second business day immediately preceding the maturity date under the following circumstances: (1) during any fiscal quarter (and only during such fiscal quarter) commencing after December 31, 2009, if the last reported sale price of our common stock is greater than or equal to 135% of the conversion price of the notes (as defined in this prospectus supplement) for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter; (2) prior to October 1, 2014, during the five business-day period after any ten consecutive trading-day period (the measurement period) in which the trading price of $1,000 principal amount of notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of our common stock and the conversion rate on such trading day; (3) if the notes have been called for redemption; or (4) upon the occurrence of one of the specified corporate transactions described in this prospectus supplement. Investors may also convert their notes at their option at any time beginning on September 1, 2029, and ending at the close of business on the second business day immediately preceding the maturity date.

The notes are convertible into shares of our common stock at a rate equal to 28.8534 shares per $1,000 principal amount of notes (equal to an initial conversion price of approximately $34.66 per share of common stock per share).

We fully paid off the second lien term loan of $75 million with proceeds received from our issuance of the 2029 Notes.

We separately account for the liability and equity components of our 5% convertible senior notes due 2029 in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. Upon issuance of the notes in September 2009, according to accounting standards related to accounting for convertible debt instruments that may be settled in cash upon conversion, we recorded a debt discount of $49.4 million, thereby reducing the carrying the value of $218.5 million notes on the December 31, 2009 balance sheet to $171.1 million and recorded an equity component net of tax of $32.1 million. The debt discount will be amortized using the effective interest rate method based upon an original five year term through October 1, 2014. Interest expense recognized relating to the contractual interest rate and amortization of both financing cost and debt discount for the year ended December 31, 2010 was $20.0 million. The effective rate on the liability component of the notes was 11.2% for the years 2010 and 2009.

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NOTE 5 Income (Loss) Per Common Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2010, 2009 and 2008. The following table sets forth information related to the computations of basic and diluted income (loss) per share.

	Year Ended December 31,		
	2010	2009	2008
	(Amounts in thousands, except per share data)		
Basic income (loss) per share:			
Income (loss) applicable to common stock	$ (268,167)	$ (257,033)	$ 115,727
Weighted-average shares of common stock outstanding (1)	35,921	35,866	33,806
Basic income (loss) per share	$ (7.47)	$ (7.17)	$ 3.42
Diluted income (loss) per share:			
Income (loss) applicable to common stock	$ (268,167)	$ (257,033)	$ 115,727
Dividends on convertible preferred stock (2)			6,047
Interest and amortization of loan cost on convertible senior notes, net of tax (3)			8,651
Diluted income (loss)	$ (268,167)	$ (257,033)	$ 130,425
Weighted-average shares of common stock outstanding (1)	35,921	35,866	33,806
Assumed conversion of convertible preferred stock (2)			3,588
Assumed conversion of convertible senior notes (3)			2,654
Stock options and restricted stock (4)			349
Weighted-average diluted shares outstanding	35,921	35,866	40,397
Diluted income (loss) per share	$ (7.47)	$ (7.17)	$ 3.23

(1) This amount does not include 1,624,300 shares in 2010, 2009 and 2008 of common stock outstanding under the Share Lending Agreement in 2010, 2009 and 2008. See Note 7.

(2) Common shares issuable upon assumed conversion of our convertible preferred stock amounting to 3,587,850 shares and the accrued dividends on the convertible preferred stock were not included in the computation of diluted loss per share for the periods presented in 2009 and 2010, as they would have been anti-dilutive.

(3) Common shares issuable upon assumed conversion of our convertible senior notes amounting to 8,958,395 shares 2010 and the accrued interest on the convertible senior notes were not included in the computation of diluted loss per for the periods presented in 2009 and 2010, as they would have been anti-dilutive.

(4) Common shares on assumed conversion of restricted stock and stock options in the amounts of 53,144 shares and 125,131 shares for the years 2010 and 2009, respectively, were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.

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NOTE 6 Income Taxes

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

	Year Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ 85	$ 5,382	$ (5,331)
State		10,070	(10,813)
	85	15,452	(16,144)
Deferred:			
Federal		48,121	(37,192)
State		3,725	(866)
		51,846	(38,058)
Total	$ 85	$ 67,298	$ (54,202)

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,		
	2010	2009	2008
Income tax (expense) benefit			
Tax at U.S. statutory income tax	$ 91,772	$ 111,412	$ (61,861)
Valuation allowance	(93,497)	(54,256)	15,268
State income taxes-net of federal benefit	1,860	10,271	(7,895)
Nondeductible expenses and other	(50)	(129)	286
Total tax (expense) benefit	$ 85	$ 67,298	$ (54,202)

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The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are presented below (in thousands):

	December 31, 2010	December 31, 2009
Current deferred tax assets:		
Accrued liabilities	$ 531	$ 980
Contingent liabilities and other	1,502	
Less valuation allowance	(1,629)	(650)
Total current deferred tax assets	404	330
Current deferred tax liabilities:		
Derivative financial instruments	(8,564)	(1,511)
Bond discount	(7,123)	
Debt discount and financing costs	(2,921)	
Accrued liabilities	(1,491)	(3,519)
Total current deferred tax liabilities	(20,099)	(5,030)
Net current deferred tax liability	$ (19,695)	$ (4,700)
Noncurrent deferred tax assets:		
Operating loss carryforwards	$ 105,105	$ 47,902
Texas Margin Credit	607	607
Louisiana NOL	877	
Statutory depletion carryforward	7,034	7,034
AMT tax credit carryforward	1,246	1,409
Derivative financial instruments		97
Compensation	3,842	3,042
Contingent liabilities and other	557	538
Property and equipment	70,619	31,572
Total gross noncurrent deferred tax assets	189,887	92,201
Less valuation allowance	(152,831)	(61,091)
Net noncurrent deferred tax assets	37,056	31,110
Noncurrent deferred tax liabilities:		
Derivative financial instruments	(3,978)	
Bond discount		(4,872)
Debt discount	(13,383)	(21,538)
Total non-current deferred tax liabilities	(17,361)	(26,410)

Net non-current deferred tax asset	$ 19,695	$ 4,700

The valuation allowance for deferred tax assets increased by $92.7 million in 2010. In determining the carrying value of a deferred tax asset, accounting standards provide 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 2010 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. Therefore, with the before-mentioned adjustment of $92.7 million, we have reduced the carrying value of our net deferred tax asset to zero. 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.

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As of December 31, 2010, we have NOL carryforwards of approximately $302.6 million for tax purposes which begin to expire in 2026. The Company also has a minimum tax credit carryforward not subject to expiration of $1.2 million which will not begin to be used until after the available NOLs have been used or expired and when regular tax exceeds the current year alternative minimum tax.

Our share based deferred compensation plans have generated $11.5 million of additional tax deductions through 2010. The Company realized $9.2 million ($6.0 million, net of tax) of these deductions in 2008 and the associated $3.2 million tax benefit was recorded as additional paid in capital. The remaining tax deductions are not currently recognized as a component of our deferred tax asset. They will be recognized when the net operating loss carryforward is utilized to offset future taxable income.

In July 2005, we received a Notice of Proposed Tax Due from the State of Louisiana asserting that we underpaid our Louisiana franchise taxes for the years 1998 through 2004 in the amount of $0.6 million. The Notice of Proposed Tax Due included additional assessments of penalties and interest in the amount of $0.4 million for a total asserted liability of $1.0 million. In order to avoid future penalties and interest, the Company paid, under protest, $1.0 million to the State of Louisiana in April 2007 which payment was expensed in general and administrative expense in first quarter 2007. We are waiting on a response from the Louisiana Department of Revenue on our settlement offer for the refund of 75% of the amount we paid under protest. Should our offer be accepted, the refund would be booked as a credit to general and administrative expense.

As of December 31, 2010, we have recorded an income tax receivable of $4.3 million of which $4.2 million is a refund due from the State of Louisiana for 2008 taxes and $0.1 million is a refund due on federal income taxes as a result of an alternative minimum tax credit refund on our 2009 income tax return.

The amount of unrecognized tax benefits did not materially change as of December 31, 2010. 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 our results of operations or our financial position. We file 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, we are no longer subject to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1992.

Our 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. We do 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, 2011.

NOTE 7 Stockholders Equity

Equity Offering

On July 14, 2008, we closed the public offering of 3,121,300 shares of our common stock at a price of $64.00 per share. Net proceeds from the offering were approximately $191.3 million after deducting the underwriters discount and estimated offering expenses. We used approximately $96.0 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility. We used the remaining net proceeds for general corporate purposes, including the funding of a portion of our 2008 drilling program, other capital expenditures and working capital requirements.

Caddo Parish Acquisition for Common Stock

In May 2008, we acquired approximately 3,665 net acres in the Longwood field of Caddo Parish, Louisiana, through the issuance of 908,098 shares of our common stock valued at approximately $33.9 million. See Note 12.

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Share Lending Agreement

In connection with the offering of our 3.25% in December 2006, we lent an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock 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 the common stock offerings and lending transactions under this agreement. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of the notes to shares of our common stock pursuant to the terms of the indenture governing the notes.

The Share Lending Agreement also requires BSC to post collateral if its credit rating is below either A3 by Moody s Investors Service (Moody s) or A-by Standard and Poor s (S&P). As a result of the long-term ratings downgrade of BSC in March 2008, BSC was required to return all or a portion of the borrowed shares or collateralize the return obligation with cash or highly liquid non-cash collateral. On March 20, 2008, BSC had returned 1,497,963 shares of the 3,122,263 originally borrowed shares and fully collateralized the remaining 1,624,300 borrowed shares with a cash collateral deposit of approximately $41.3 million. This amount represents the market value of the remaining borrowed shares at March 20, 2008. Under certain conditions, BSC is required to maintain collateral value in the amount at least equal to the market value of the outstanding borrowed shares. The 1,497,963 shares returned to us were recorded as treasury stock and retired in March 2008.

In May 2008, JP Morgan Chase & Co. completed its acquisition of and assumed all counterparty liabilities of The Bear Stearns Companies Inc. JP Morgan Chase & Co. s credit rating exceeds that required by the Share Lending Agreement. Thus, collateral is no longer required. Should JP Morgan Chase & Co. s credit ratings decline below either A3 by Moody s or A- by S&P, it would be required to post collateral to support its obligation to return any remaining borrowed shares.

The 1,624,300 shares of common stock outstanding as of December 31, 2010, under the Share Lending Agreement have a fair value of $28.7 million based on a closing price on December 31, 2010 of $17.64 per share and are required to be returned to us in the future. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. As a result, the shares of common stock lent under the Share Lending Agreement have no impact on the earnings per share calculation.

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 agreements were separate transactions entered into by us with the option counterparties and was not part of the offering of common stock. 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. Approximately 77,333 options per trading day expired over each of three separate 25 consecutive trading day settlement periods. During 2009, two-thirds of the options expired. The remaining one-third of the options subject to the capped call expired in May and June 2010 and did not result in our receipt of any shares of common stock.

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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 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 the 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.

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NOTE 8 Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices and interest rates. We are currently not designating our derivative contracts for hedge accounting. All gains and losses both realized and unrealized from our derivative contracts have been recognized in other income (expense) on our Consolidated Statement of Operations.

The total financial impact of our derivative activities on our consolidated Statement of Operations for the year ended December 31, 2010 was a $55.3 million gain which consisted of $23.5 million in realized gain in addition to the $31.8 million in unrealized gain.

Commodity Derivative Activity

We enter into swap contracts, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production. Our strategy, which is administered by the Hedging Committee of our Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our estimated total production for the period the derivatives are in effect. As of December 31, 2010, the commodity derivatives we used were in the form of:

(a) 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

(b) basis swaps, where we receive an index price less a fixed amount and pay a floating price, based on NYMEX or specific transfer point quoted prices.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2010, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, Bank of Montreal or Royal Bank of Canada, were as follows:

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Average Floor/Cap**		**Fair Value at December 31, 2010**
Natural gas (MMBtu)					$ 38,378,059
1Q 2011	40,000	3,600,000	$ 6.00	$7.09	
2Q 2011	40,000	3,640,000	$ 6.00	$7.09	
3Q 2011	40,000	3,680,000	$ 6.00	$7.09	
4Q 2011	40,000	3,680,000	$ 6.00	$7.09	
1Q 2012	40,000	3,640,000	$ 6.00	$7.09	
2Q 2012	40,000	3,640,000	$ 6.00	$7.09	
3Q 2012	40,000	3,680,000	$ 6.00	$7.09	
4Q 2012	40,000	3,680,000	$ 6.00	$7.09	
			Fixed Price		
Oil Swaps (BBL)					$ 1,820,994
1Q 2011	800	72,000	$100.00		
2Q 2011	800	72,800	$100.00		
3Q 2011	800	73,600	$100.00		
4Q 2011	800	73,600	$100.00		
Oil Swaptions (BBL) (1)					$ (4,367,301)
2012	800	292,800	$100.00		
2013	800	292,000	$100.00		
			Total		$ 35,831,752

(1) Swaption whereby the payer (counter party) has the option to enter into the swap agreement.

The fair value of the oil and gas commodity contracts in place at December 31, 2010, that are marked to market resulted in a current asset of $24.5 million, a long-term asset of $15.7 million and a long-term liability of $4.4 million. We measure the fair value of our commodity derivatives contracts by applying the income approach, and these contracts are classified within level two of the valuation hierarchy. See Note 13. For the year ended December 31, 2010, we recognized in earnings a $55.3 million gain from these commodity derivative instruments, which consisted of $24.6 million in realized gain and $30.7 million in unrealized gain.

Interest Rate Swap

We have variable-rate debt obligations that expose 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. These swaps are not designated as hedges. At December 31, 2010, we had no interest rate swaps in place.

NOTE 9 Commitments and Contingencies

Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC et al. On April 29, 2010 a state court in Caddo Parish, Louisiana, granted a judgment holding the Company solely responsible for the payment of $8.5 million in additional oil and gas lease bonus payments and related interest in an ongoing lawsuit involving the interpretation of a unique oil and gas lease provision. The lease provided for the payment of additional bonuses under certain circumstances in the event higher lease bonuses were paid by the Company, its successors or

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assigns, within the surrounding area. Without the Company s knowledge, one of the sub-lessees subject to the same lease paid substantially higher bonuses in the area. The Company believes that this ruling was improperly decided and, on July 8, 2010, filed a motion for suspensive appeal. The Company satisfied the requirements for posting a suspensive appeal bond by depositing $8.5 million in July 2010 with Iberia Bank in Shreveport, Louisiana for the account of the Clerk of Caddo Parish Court.

On July 9, 2010, the sub-lessee agreed to reimburse us for one half of any sums for which we may be cast in judgment in this lawsuit in any final non-appealable judgment, and further agreed to reimburse us for one half of the cash bond. We reduced our accrual by $4.2 million in the third quarter of 2010 and the remaining $4.3 million as of December 31, 2010 is reflected as Operating Expenses Other in the Consolidated Statement of Operations.

In addition, we are party to other 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 consolidated financial position or results of operations or liquidity.

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, 2010 (in thousands).

			Payment due by Period (2)				
	Note	**Total**	**2011**	**2012**	**2013**	**2014**	**2015 and After**
Long term debt (1)	4	$ 393,500	$ 175,000	$	$	$ 218,500	$
Interest on convertible senior notes	4	46,182	16,138	10,925	10,925	8,194	
Office space leases	10	9,246	1,042	1,044	1,142	1,104	4,914
Office equipment leases	10	793	496	114	100	56	27
Drilling rigs & operations contracts	10	27,179	18,744	7,702	583	150	

(1) The $175.0 million 2026 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. The $218.5 million 5.0% convertible senior notes have a provision by which on or after October 1, 2014, the Company may redeem all or a portion of the notes for cash, and the investors may require the Company to repurchase the notes on each of October 1, 2014, 2019 and 2024.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and gas properties of $16.1 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3.

Operating Leases We have commitments under an operating lease agreement for office space and office equipment leases. Total rent expense for the years ended December 31, 2010, 2009, and 2008, was approximately $1.1 million, $1.1 million and $0.9 million.

Drilling Contracts We have three drilling rigs under contract as of December 31, 2010 of which two are scheduled to expire in 2011 and one is scheduled to expire in 2012.

Litigation 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.

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NOTE 10 Related Party Transactions

Patrick E. Malloy, III, Chairman of the Board of Directors of our company is a principal of Malloy Energy Company, LLC (MEC). MED owns various small working interests in the Bethany Longstreet and Plumb Bob fields for which we are the operator. In accordance with industry standard joint operating agreements, we bill MEC for its share of capital and operating cost on a monthly basis. As of December 31, 2010 and 2009, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $0.5 million and $1.4 million, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by MEC to us in the month after billing and the affiliate is current on payment of its billings.

At the same time we sold a portion of our interests in the Haynesville Shale deep rights at Bethany Longstreet field, MEC consummated a similar transaction for its 30% working interest in the same deep rights with Chesapeake. We and MEC also sold our interest in the St. Gabriel field in August 2008. In December 2010, MEC sold their shallow interest in the Bethany Longstreet field.

We also serve as the operator for a number of other oil and gas wells owned by affiliates of MEC in which we will earn an average working interest of 11% after payout. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2010 and 2009, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were less than $0.1 million at the end of 2010 and 2009 and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month after billing and the affiliate is current on payment of its billings.

On May 25, 2010, we entered into a participation agreement with Turnham Interests, Inc., a private company owned by Robert C. Turnham, Jr. (the Turnham Participation Agreement) on terms substantially identical to recent transactions, as described below. Mr. Turnham is our President and Chief Operating Officer and is a member of our Board of Directors. Pursuant to the Turnham Participation Agreement, we purchased from Turnham Interests, Inc., at a cash price of $1,250 per net acre, a 95% working interest in approximately 813 net acres in the Eagle Ford Shale oil play in Frio County, Texas. In addition, we agreed to pay for and carry the costs associated with the drilling and completion of an initial well on the acreage, to the extent such costs are attributable to the 5% working interest in such acreage retained by Turnham Interests, Inc. The total cash consideration received by Turnham Interests, Inc. was approximately $1 million. The term of the Turnham Participation Agreement is three years, or for so long as there is commercial production from the acreage.

The terms of the Turnham Participation Agreement are substantially identical to the terms of a previously announced participation agreement entered into between us and an unrelated third party, concerning approximately 6,000 net acres adjacent to the acreage covered by the Turnham Participation Agreement. Turnham Interests, Inc. had owned the leasehold interest subject to the Turnham Participation Agreement since 1999.

NOTE 11 Acquisitions and Divestitures

Acquisitions

In December 2009, we acquired lease interests in approximately 12,000 net acres in Nacogdoches and Angelina Counties of Texas which is believed to be prospective for the Haynesville Shale. Total consideration paid was $9.2 million.

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In April 2010, we acquired a leasehold interest within the oil window of the Eagle Ford Shale play in La Salle and Frio Counties, Texas. We paid approximately $10.0 million in upfront cash and have the option to drill to earn the full interest through $44.0 million in carried drilling costs. At September 30, 2010, we had invested a total of $22 million in leasehold acreage in the Eagle Ford Shale play.

Divestitures

On June 16, 2008, we entered into a joint development agreement with Chesapeake to develop our Haynesville Shale acreage in the Bethany Longstreet and Longwood fields of Caddo and DeSoto Parishes, Louisiana. Chesapeake purchased the deep rights to approximately 10,250 net acres of oil and natural gas leasehold comprised of a 20% working interest in approximately 25,000 net acres in the Bethany Longstreet field and a 50% working interest in approximately 10,500 net acres in the Longwood field for $172.6 million. The sale closed on July 15, 2008, resulting in net proceeds of $172.0 million and a gain on the transaction of $145.1 million. Chesapeake also purchased 7,500 net acres of deep rights in the Bethany Longstreet field from a third party, bringing the ownership interest in the deep rights in both fields after closing to 50% each for us and Chesapeake.

On December 30, 2010, we sold the shallow rights in certain of our non-core properties located in Northwest Louisiana and East Texas for approximately $65 million with an effective date of July 1, 2010. The Company has retained all of the deep drilling rights on these divested properties, including the rights to both the Haynesville Shale and Bossier Shale formations.

NOTE 12 Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company s credit risk.

We use various methods, including the income approach and market approach, to determine the fair values of our financial instruments that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments into three levels (levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels.

Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 Inputs unadjusted quoted market prices in active markets for identical assets or liabilities.

Level 2 Inputs quotes which are derived principally from or corroborated by observable market data. Included in this level are our long-term debt and our interest rate swaps and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties.

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Level 3 Inputs unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices. Included in this level are our assets held for sale and oil and gas properties which are deemed impaired.

As of December 31, 2010 and 2009, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each level as of December 31, 2010 and 2009 (in thousands):

	2010 Fair Value Measurements Using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current Assets Commodity Derivatives	$	$ 24,467	$	$ 24,467
Non-current Assets Commodity Derivatives		15,732		15,732
Non-current Liabilities Commodity Derivatives		(4,367)		(4,367)
Total	$	$ 35,832	$	$ 35,832

	2009 Fair Value Measurements Using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current Assets -Commodity Derivatives	$	$ 5,403	$	$ 5,403
Current Liabilities Interest Swaps		(1,087)		(1,087)
Non-current Liabilities Interest Swaps		(278)		(278)
Total	$	$ 4,038	$	$ 4,038

The following table reflects the carrying value, as recorded in our Consolidated Balance Sheet and fair value of our debt financial instruments which we classified as level 2 at December 31, 2010 and 2009 (in thousands):

	2010		2009	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
3.25% Convertible Senior Notes due 2026	167,089	173,478	159,085	161,438
5.0% Convertible Senior Notes due 2029	179,168	212,164	171,062	226,694

Total debt	$ 346,257	$ 385,642	$ 330,147	$ 388,132

The fair value amounts of our debt are based on quoted market prices for the same or similar type issues.

NOTE 13 Impairment of oil and gas properties

Methods for Determining Fair Value

We periodically assess our long-lived assets recorded in oil and gas properties on the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value, which is computed using level 3 inputs such as discounted cash flow models or valuations, based on estimated future commodity prices and our various operational assumptions. At least semi-annually or whenever changes in facts and circumstances indicate that our oil and gas properties may be impaired; an evaluation is performed on a field-by-field basis.

As of December 31, 2010, we had interests in oil and gas properties totaling $535.8 million, net of accumulated depletion, which we account for under the successful efforts method. The expected future cash

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimated future net cash flows generated from our oil and gas properties by using forecasted oil and gas prices.

Impairment of Oil and Gas Properties

Due to declines in natural gas prices during 2010, we determined that the carrying amount of certain of our oil and gas properties were not recoverable from future cash flows and, therefore, were impaired. We recorded an impairment of $234.9 million for the year ended December 31, 2010. The expected future cash flows used for our impairment review and related fair-value calculation was based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimated future net cash flows generated from our oil and gas properties by using forecasted oil and gas prices

Total impairment associated with our oil and gas properties for the years ended December 31, 2010, 2009 and 2008 was $234.9 million, $208.9 million and $28.6 million, respectively.

NOTE 14 Resignation of Executive Officer

In March 2010, David R. Looney resigned as Executive Vice President and Chief Financial Officer of the Company. The provisions of the Resignation Agreement dated March 24, 2010 among the Company and Mr. Looney consisted primarily of the following:

- Term life of 60,000 fully vested options was modified;
- Accelerated vesting of 25,000 shares of restricted stock; and
- Execution of a consulting agreement for six months through September 2010.

The Company recognized additional expense related to the Resignation Agreement of approximately $0.9 million during the year ended December 31, 2010.

NOTE 15 Oil and Gas Producing Activities (Unaudited)

Overview

All of our reserve information related to crude oil, condensate, and natural gas liquids and natural gas was compiled based on estimates prepared and reviewed by our engineers. The technical persons primarily responsible for overseeing the preparation of the reserves estimates meet the requirements regarding qualifications. The reserves estimation is part of our internal controls process subject to management s annual review and approval. These reserves estimates are evaluated and audited by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers consulting firm, as of December 31, 2010, 2009 and 2008. A report of NSAI is filed in Exhibit 99.1. All of the subject reserves are located in the continental United States, primarily in Texas and Louisiana.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Regulations published by the SEC define proved oil and gas reserves as those quantities of oil and gas which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

In December 2008, the SEC issued a final rule adopting revisions to its oil and gas reporting disclosures. The revisions are intended to provide investors with more meaningful and comprehensive information related to the determination and disclosure of oil and gas reserves information. In January 2010, the FASB issued an update to accounting standards for oil and gas reserve estimations and disclosures. The provisions of both SEC final rule and FASB accounting update are effective for fiscal years ending on or after December 31, 2009. We adopted both SEC final rule and FASB accounting update on their effective date of December 31, 2009. The rule changes, including those related to pricing and technology, are included in our reserves estimates as of December 31, 2010 and 2009. Our reserves estimates as of December 31, 2008 were prepared under the previous rules.

Prices we used to value our reserves are based on the twelve-month un-weighted arithmetic average of the first-day-of-the-month price for the period January through December 2010. For oil volumes, the average WTI spot price of $75.96 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.38 per MMBtu is adjusted by lease for energy content, transportation fees, and regional price differentials.

Capitalized Costs

The table below reflects our capitalized costs related to our oil and gas producing activities at December 31, 2010, and 2009 (in thousands):

	2010	**2009**
Proved properties	$ 1,162,017	$ 1,305,694
Unproved properties	55,874	37,931
	1,217,891	1,343,625
Less accumulated depreciation, depletion and amortization	(682,056)	(671,352)
Net oil and gas properties	$ 535,835	$ 672,273

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Costs Incurred

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Property Acquisition			
Unproved	$ 33,456	$ 15,264	$ 54,657
Proved		579	7,751
Exploration	33,580	35,378	44,765
Development (1)	218,342	193,130	315,030
	$ 285,378	$ 244,351	$ 422,203

(1) Includes asset retirement costs of $1.3 million in 2010, $3.7 million in 2009 and $7.4 million in 2008.

The following table sets forth our net proved oil and gas reserves at December 31, 2010, 2009 and 2008 and the changes in net proved oil and gas reserves during such years:

	Natural Gas (MMcf)			Oil (MBbls)		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Proved reserves at beginning of period	415,301	390,449	346,930	877	1,983	1,810
Revisions of previous estimates (1)	1,383	(264,928)	(62,616)	88	(1,441)	(137)
Extensions, discoveries and improved recovery (2)	102,751	318,699	126,350	820	487	470
Purchases of minerals in place			2,988			15
Sales of minerals in place	(32,431)	(28)	(14)	(17)		(1)
Production	(32,815)	(28,891)	(23,189)	(150)	(152)	(174)
Proved reserves at end of period	454,189	415,301	390,449	1,618	877	1,983
Proved developed reserves:						
Beginning of period	162,935	150,174	108,077	431	387	282
End of period	187,417	162,935	150,174	746	431	387

	Natural Gas Equivalents (MMcfe)		
	2010	**2009**	**2008**
Proved reserves at beginning of period	420,561	402,349	357,792
Revisions of previous estimates (1)	1,916	(273,577)	(63,438)
Extensions, discoveries and improved recovery (2)	107,670	321,622	129,170
Purchases of minerals in place			3,078
Sales of minerals in place (3)	(32,532)	(28)	(20)
Production	(33,716)	(29,805)	(24,233)
Proved reserves at end of period	463,899	420,561	402,349
Proved developed reserves:			
Beginning of period	165,519	152,496	109,769
End of period	191,893	165,519	152,496

(1) Revisions of previous estimates in 2008 and 2009 were negative due primarily to significant pricing decreases in 2008 and 2009 which caused a number of our vertical proved undeveloped locations in Northwest Louisiana and East Texas areas to become uneconomic at those lower price levels.

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(2) Extensions and discoveries were positive on an overall basis in all three periods presented, primarily related to our continued drilling activity on existing and newly acquired properties in the Northwest Louisiana, East Texas and South Texas areas. We recognized reserve adds of 108 Bcfe in 2010 related to extensions and discoveries, of which approximately 80 Bcfe is attributed to the Haynesville Shale Trend, approximately 25 Bcfe is attributed to the Cotton Valley Taylor Sand and approximately 3 Bcfe is attributed to the Eagle Ford Shale Trend.

(3) In December 2010, we sold approximately 33 Bcfe attributed to our shallow rights in several fields in East Texas and Northwest Louisiana retaining ownership of all the deep rights including the Haynesville Shale Trend formations.

Standardized Measure

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

	2010	2009	2008
Future revenues	$ 1,835,800	$ 1,267,712	$ 2,052,735
Future lease operating expenses and production taxes	(424,560)	(420,687)	(816,941)
Future development costs (1)	(513,252)	(422,042)	(675,787)
Future income tax expense	(10,172)	(3,384)	(6,907)
Future net cash flows	887,816	421,599	553,100
10% annual discount for estimated timing of cash flows	(529,138)	(274,375)	(385,657)
Standardized measure of discounted future net cash flows	$ 358,678	$ 147,224	$ 167,443
Index price used to calculate reserves (2)			
Natural gas (per Mcf)	$ 4.38	$ 3.87	$ 5.71
Oil (per Bbl)	$ 75.96	$ 57.65	$ 41.00

(1) Includes cumulative asset retirement obligations of $16.1 million, $18.3 million and $13.8 million in 2010, 2009 and 2008, respectively.

(2) These index prices, used to estimate our reserves at these dates, are before deducting or adding applicable transportation and quality differentials on a well-by-well basis.

We believe with reasonable certainty that we will be able to obtain such capital in the normal course of business. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

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Changes in the Standardized Measure

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

	Year Ended December 31, 2010	2009	2008
Balance, beginning of year	$ 147,224	$ 167,443	$ 284,117
Net changes in prices and production costs related to future production	113,068	(309,832)	(68,643)
Sales and transfers of oil and gas produced, net of production costs	(108,242)	(66,438)	(167,516)
Net change due to revisions in quantity estimates	1,962	(181,646)	(81,292)
Net change due to extensions, discoveries and improved recovery	153,509	89,811	105,257
Net change due to purchases and sales of minerals in place	(12,979)	3	5,219
Changes in future development costs	35,173	473,897	3,426
Previously estimated development cost incurred in period	21,231	6,160	35,926
Net change in income taxes	(2,507)	1,461	26,165
Accretion of discount	14,816	16,987	31,269
Change in production rates (timing) and other	(4,577)	(50,622)	(6,485)
Net increase (decrease) in standardized measures	211,454	(20,219)	(116,674)
Balance, end of year	$ 358,678	$ 147,224	$ 167,443

NOTE 16 Summarized Quarterly Financial Data (Unaudited)

(In Thousands, Except Per Share Amounts)

	First Quarter	Second Quarter	Third Quarter (1)	Fourth Quarter	Total
2010					
Revenues	$ 40,455	$ 34,162	$ 37,424	$ 36,292	$ 148,333
Operating loss	(21,331)	(12,777)	(238,482)	(7,828)	(280,418)
Net income (loss)	4,331	(21,599)	(225,131)	(19,721)	(262,120)
Net income (loss) applicable to common stock	2,819	(23,111)	(226,642)	(21,233)	(268,167)
Basic income (loss) per common share	0.08	(0.64)	(6.31)	(0.59)	(7.47)
Diluted income (loss) per common share	0.08	(0.64)	(6.31)	(0.59)	(7.47)

2009					
Revenues	$ 28,461	$ 26,263	$ 23,525	$ 32,177	$ 110,426
Operating income (loss)	(27,546)	(53,947)	(37,740)	(220,489)	(339,722)
Net income (loss)	3,144	(34,982)	(29,519)	(189,629)	(250,986)
Net income (loss) applicable to common stock	1,632	(36,494)	(31,031)	(191,140)	(257,033)
Basic income (loss) per common share	0.05	(1.02)	(0.87)	(5.34)	(7.17)
Diluted income (loss) per common share	0.05	(1.02)	(0.87)	(5.34)	(7.17)

(1) The carrying amount of our oil and natural gas properties was impaired by $234.9 million as of September 30, 2010. This amount includes an increase of $11.6 million from the previously reported amount of $223.3 million as a result of further review of our September 30, 2010 impairment analysis.

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

None.

Item 9A. ***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, 2010, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Management s Annual Report on Internal Control Over Financial Reporting

See *Management s Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

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 February 17, 2011, are as follows:

Name	Age	Position
Patrick E. Malloy, III	68	Chairman of the Board of Directors
Walter G. Gil Goodrich	52	Vice Chairman, Chief Executive Officer and Director
Robert C. Turnham, Jr.	53	President, Chief Operating Officer and Director
Mark E. Ferchau	56	Executive Vice President Operations
Jan L. Schott	42	Senior Vice President and Chief Financial Officer
Michael J. Killelea	48	Senior Vice President, General Counsel and Corporate Secretary
Henry Goodrich	80	Chairman Emeritus and Director
Josiah T. Austin	64	Director
Geraldine A. Ferraro	75	Director
Michael J. Perdue	56	Director
Arthur A. Seeligson	52	Director
Stephen M. Straty	55	Director
Gene Washington	64	Director

Josiah T. Austin has served as one of our directors since 2002. Mr. 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. Additionally, Mr. Austin was elected to the Board of North Fork Bancorporation, Inc. in 2004. Mr. Austin now serves on the board of Novogen Ltd.

Mark E. Ferchau has served as an Executive Vice President since April 2004. He originally joined us in September 2001, and from 2003 to 2004 he served as our Senior Vice President, Engineering and Operations. Mr. Ferchau has over 30 years of experience in the energy industry and has worked for several public and private oil and natural gas exploration and production companies in various positions.

Geraldine A. Ferraro has served as one of our directors since 2003. Ms. Ferraro was a principal in the government relations practice of Blank Rome LLP, a national law firm from 2007 until her retirement in January, 2010. Previously, 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 the U.S. House of Representatives for three terms before accepting the Democratic nomination for Vice-President in 1984, and has been affiliated with numerous public and private sector political, governmental, social and other organizations.

Henry Goodrich has served as one of our directors since 1995. He served as Chairman of our Board from March 1996 through February 2003 and as Chairman Emeritus since that date. Mr. Goodrich founded Goodrich Oil Company, one of our predecessors, in 1975. In total, he has over 50 years of experience in the exploration and production industry. Mr. Goodrich is the father of Walter G. Goodrich, who is our Chief Executive Officer and a director on our Board.

Walter G. Gil Goodrich has served as our Chief Executive Officer and as one of our directors since 1995. He became Vice Chairman of our Board in 2003. Mr. Goodrich has over 30 years of experience in the exploration and production industry. He joined Goodrich Oil Company, one of our predecessors, as an exploration geologist in 1980, where he served as Vice President of Exploration from 1985 to 1989 and President from 1989 to August 1995. Mr. Goodrich is the son of Henry Goodrich, another of our directors.

Michael J. Killelea joined us as Senior Vice President, General Counsel and Corporate Secretary in January 2009. Mr. Killelea has over 23 years of experience in the energy industry. In 2008, he served as Vice President,

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General Counsel and Corporate Secretary for Maxus Energy Corporation, private oil and gas exploration and production company located in The Woodlands, Texas. Prior to that time, Mr. Killelea was Senior Vice President, General Counsel and Corporate Secretary of Pogo Producing Company, a publicly traded oil and gas exploration and production company headquartered in Houston, Texas, from 2000 through 2007.

Patrick E. Malloy, III has served as one of our directors since 2000. He became Chairman of the Board in February 2003. Mr. Malloy is the President and Chief Executive Officer of Malloy Enterprises, Inc., a real estate and investment holding company, a position he has held since 1973.

Michael J. Perdue has served as one of our directors since 2001. He is the President of PacWest Bancorp, a publicly traded holding company and of its subsidiary, Pacific Western Bank, both based in San Diego, California. Before assuming his present position in 2006, Mr. Perdue served as President and Chief Executive Officer of Community Bancorp Inc., from 2003. Over the course of his career, Mr. Perdue has held executive positions with several banking and real estate development organizations.

Arthur A. Seeligson has served as one of our directors since 1995. He has been the Managing Partner of Seeligson Oil Company Ltd. since 1996 and also manages a family investment office in Houston. Previously, Mr. Seeligson was an investment banker focused on the oil and gas industry.

Jan L. Schott was promoted to Senior Vice President and Chief Financial Officer on May 20, 2010. Ms. Schott was named Vice President and Interim CFO on March 24, 2010. Ms. Schott joined the Company in 2007 as Vice President and Controller of the Company. Ms. Schott serves as the Company s Principal Financial Officer. Prior to joining the Company, Ms. Schott served in various accounting management positions with Apache Corporation from 1997 to 2006. Prior to joining Apache Corporation, Ms. Schott was in public accounting with KPMG LLP from 1991 to 1997. Ms. Schott is a Certified Public Accountant.

Stephen M. Straty has served as one of our directors since 2009. He is the Co-Head and a Managing Director of the Energy Investment Banking Group at Jefferies and Company, Inc. Mr. Straty joined the firm in 2008 and has 30 years of experience in finance, most recently as Senior Managing Director and Head of the Natural Resources Group at Bear, Stearns & Co., Inc. where he worked for 17 years. Mr. Straty has extensive experience in serving a broad array of energy clients, having completed over $40.0 billion in merger and acquisition and financing assignments during the past ten years.

Robert C. Turnham, Jr. has served as one of our directors since 2006. Mr. Turnham joined Goodrich as Chief Operating Officer in 1995 and became President and Chief Operating Officer in 2003. He has held various positions in the oil and natural gas business since 1981. His experience includes positions in both financial and executive management positions.

Gene Washington has served as one of our directors since 2003. He recently retired from his position as Director of Football Operations with the National Football League, a position he had held since 1994. He previously served as a professional sportscaster and as Assistant Athletic Director for Stanford University. Mr. Washington serves and has served on numerous corporate and civic boards, including his current service as a director for dELiA*s, Inc., a NYSE-listed company.

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 2011 Annual Meeting of Stockholders. . The information required by this Item is incorporated by reference to the information provided in our definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010. 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.*

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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 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

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 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

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 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

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 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

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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 46.

All schedules are omitted because they are not applicable, not required or the information is included within the consolidated financial information or related notes.

(a)(3) Exhibits

2.1	Purchase Agreement by and between Goodrich Petroleum, L.L.C. and SND Operating, L.L.C., dated October 27, 2010 (Incorporated by reference to exhibit 2.1 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on January 4, 2011).
3.2	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Acquisition II, Inc., dated January 31, 1997 (Incorporated by reference to Exhibit 3.1 B of the Company s Third Amended Registration Statement of Form S-1 (Registration No. 333-47078) filed on December 8, 2000.
3.3	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated March 12, 1998 (Incorporated by reference to Exhibit 3.2 of the Company s Annual Report on Form 10-K (File No. 001-12719) for the year ended December 31, 1997).
3.4	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated May 9, 2002 (Incorporated by reference to Exhibit 3.4 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on December 3, 2007).
3.5	Certificate of Amendment of 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 (File No. 001-12719) filed on August 9, 2007).
3.6	Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.2 of the Company s Form 8-K (File No. 001-12719) filed February 19, 2008).
3.7	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 (File No. 001-12719) 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	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 (File No. 001-12719) filed on December 22, 2005).
4.4	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 (File No. 001-12719) for the year ended December 31, 2006).
4.5	Indenture, dated as of September 28, 2009, between Goodrich Petroleum Corporation and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on

September 30, 2009).

4.6 First Supplemental Indenture dated as of September 28, 2009, between Goodrich Petroleum Corporation and Wells Fargo Bank, National Association, as trustee (Incorporated by reference to Exhibit 4.2 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on September 30, 2009).

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4.7	Form of 5.00% Convertible Senior Note due 2029 (Incorporated by reference to Exhibit 4.3 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on September 30, 2009).
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. 333-58631)).
10.2	Goodrich Petroleum Corporation 2006 Long-Term Incentive Plan (Incorporated by reference to the Company s Proxy Statement (File No. 001-12719) filed April 17, 2006).
10.3	Goodrich Petroleum Corporation 1997 Non-Employee Director Compensation Plan (Incorporated by reference to the Company s Proxy Statement (File No. 001-12719) filed April 27, 1998 (File No. 001-12719)).
10.4	Goodrich Petroleum Corporation Annual Bonus Plan (Incorporated by reference to Exhibit 10.5 of the Company s Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 8, 2007).
10.5	Non-employee Director Compensation Summary (Incorporated by reference to Exhibit 10.49 of the Company s Annual Report on Form 10-K for the year ended December 31, 2007).
10.6	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 (File No. 001-12719) dated October 15, 1999 (File No. 001-12719)).
10.7	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 (File No. 333-138156) filed on October 23, 2006).
10.8	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 (File No. 333-138156) filed on October 23, 2006).
10.9	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 (File No. 333-138156) filed on October 23, 2006).
10.10	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 (File No. 333-138156) filed on October 23, 2006).
10.11	Form of Incentive Stock Option Agreement (Incorporated by reference to Exhibit 4.6 to the Company s Registration Statement on Form S-8 (File No. 333-138156) filed on October 23, 2006).
10.12	Form of Nonqualified Option Agreement (Incorporated by reference to Exhibit 4.7 to the Company s Registration Statement on Form S-8 (File No. 333-138156) filed on October 23, 2006).
10.13	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)).
10.14	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 (File No. 001-12719) filed on November 8, 2007).
10.15	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 (File No. 001-12719) filed on November 8, 2007).
10.16	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 (File No. 001-12719) filed on November 8, 2007).

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10.17	Second Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and certain lenders dated May 5, 2009 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q (File No. 001-12719) filed on May 7, 2009).
10.18	First Amendment to Second Amended and Restated Credit Agreement between Goodrich Petroleum Company, L.L.C. and BNP Paribas and certain lenders, dated as of September 22, 2009 (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on September 28, 2009).
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 (File No. 001-12719) filed on December 4, 2006).
10.20	Resignation Agreement dated as of March 24, 2010 between David R. Looney and Goodrich Petroleum Corporation (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K (File No. 001-12719) filed on March 26, 2010).
10.21	Participation Agreement between the Company and Turnham Interests, Inc. dated May 25, 2010 (Incorporated by reference to Exhibit 10.1 of the Company s Quarterly Report on Form 10-Q (File No. 001-12719) filed on August 5, 2010).
10.22	Third Amendment to Second Amended and Restated Credit Agreement dated as of February 4, 2011 among Goodrich Petroleum Company, L.L.C., BNP Paribas, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on February 10, 2011).
10.23	Second Amendment to Second Amended and Restated Credit Agreement dated as of October 29, 2010 among Goodrich Petroleum Company, L.L.C., BNP Paribas, as administrative agent, and the lenders party thereto(Incorporated by reference to Exhibit 10.2 of the Company s Current Report on Form 8-K (File No. 001-12719) filed on February 10, 2011).
12.1*	Ratio of Earnings to Fixed Charges.
12.2*	Ratio of Earnings to Fixed Charges and Preference Securities Dividends.
21	Subsidiary of the Registrant:
	Goodrich Petroleum Company LLC Organized in the State of Louisiana.
23.1*	Consent of Ernst & Young 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.
99.1**	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
101.INS	XBRL Instance Document

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101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Labels Linkbase Document
101.PRE	XBRL Presentation Linkbase Document
101.DEF	XBRL Definition Linkbase Document

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

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 an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Economically producible as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil-and-gas producing activities.

Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

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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. The SEC provides a complete definition of field in Rule 4-10(a)(15).

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 the 12-month average price for the year and holding that price 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 an exploratory, development or extension well that is not a dry well.

Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future reconditions. The SEC provides a complete definition of proved reserves in Rule 4-10(a)(22) of Regulation S-X.

Developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

Reasonable certainty means a high degree of confidence that the quantities will be recovered, if deterministic methods are used. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease. The deterministic method of estimating reserves or resources uses a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation. The probabilistic method of estimation of reserves or resources uses the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, the legal right to produce or a revenue interest in the production, installed means of

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delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Undeveloped reserves are 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. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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.

Gross well or acre is a well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. Count one or more completions in the same bore hole as one well. In a footnote, disclose the number of wells with multiple completions. If one of the multiple completions in a well is an oil completion, classify the well as an oil well.

Net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

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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, on February 21, 2011.

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 Jan L. Schott 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 February 17, 2011.

Signature	Title
/s/ WALTER G. GOODRICH **Walter G. Goodrich**	Vice Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ JAN L. SCHOTT **Jan L. Schott**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DAWN K. SMAJSTRLA **Dawn K. Smajstrla**	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.	President, Chief Operating Officer and Director

Robert C. Turnham, Jr.	
/s/ Josiah T. Austin	Director
Josiah T. Austin	
/s/ Geraldine A. Ferraro	Director
Geraldine A. Ferraro	
/s/ Henry Goodrich	Director
Henry Goodrich	
/s/ Michael J. Perdue	Director
Michael J. Perdue	

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Signature	Title
/s/ ARTHUR A. SEELIGSON	Director
Arthur A. Seeligson	
/s/ STEPHEN M. STRATY	Director
Stephen M. Straty	
/s/ GENE WASHINGTON	Director
Gene Washington	

EXHIBIT INDEX

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Consent of Independent Petroleum Engineers and Geologists	23.2
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XBRL Schema Document	101.SCH
XBRL Calculation Linkbase Document	101.CAL
XBRL Labels Linkbase Document	101.LAB
XBRL Presentation Linkbase Document	101.PRE
XBRL Definition Linkbase Document	101.DEF