GOODRICH PETROLEUM CORP
Form 10-K
February 26, 2010
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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, 2009

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 x No ¨

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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 ¨ 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 x Accelerated filer ¨ 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, 2009) the last business day of the registrant s most recently completed second fiscal quarter was approximately $573 million. The number of shares of the registrant s common stock outstanding as of February 24, 2010 was 37,519,966.

Documents Incorporated By Reference:

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

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GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2009

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PART I

Items 1. and 2. *Business and Properties*

General

Goodrich Petroleum Corporation and its subsidiaries (together, we or the Company) is an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in East Texas and Northwest Louisiana. The geological formations found in East Texas and Northwest Louisiana generally provide multiple pay objectives including: the Haynesville Shale, Cotton Valley, Travis Peak, James and Pettet formations. While we believe all of the various play objectives underlying our properties can be economically developed at higher commodity prices, in the current price environment we are concentrating our development efforts on horizontal drilling in the Haynesville Shale and, to a lesser extent, the Cotton Valley Taylor sand. We continue to aggressively pursue the evaluation and acquisition of prospective acreage, oil and gas drilling opportunities and potential property acquisitions. We own working interests in 466 active oil and gas wells located in 24 fields in six states. At December 31, 2009, we had estimated proved reserves of approximately 415.3 Bcf of natural gas and 0.9 MMBbls of oil and condensate, or an aggregate of 420.6 Bcfe with a pre-tax present value of future net cash flows, discounted at 10%, or PV-10, of $148.2 million and a related standardized measure of discounted future net cash flows of $147.2 million, which reflects the after-tax present value of discounted future net cash flows. See the table included in the Oil and Natural Gas Reserves section on page 6 for a reconciliation of PV-10 to the standardized measure of discounted future net cash flows.

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

2009 Highlights

- We achieved annual production volume growth of 23% with production volume growing from 24.2 Bcfe in 2008 to 29.8 Bcfe in 2009.

- We leased additional acreage in the Haynesville Shale play in Northwest Louisiana and East Texas, increasing our ownership to approximately 85,000 net acres at December 31, 2009.

- We drilled and completed 45 gross (25 net) wells in 2009, with a success rate of 100% of which 32 gross wells were in the Haynesville Shale.

- We raised $218.5 million from our 5% Convertible Senior Notes offering in September 2009.

- We exited the year with estimated proved reserves of approximately 420.6 Bcfe (approximately 415.3 Bcf of natural gas and 0.9 MMBbls of oil and condensate), with a PV-10 of $148.2 million and a standardized measure of $147.2 million, approximately 39% of which is proved developed.

Business Strategy

Our business strategy is to provide long term growth in net asset value per share, through the growth and expansion of our oil and gas production and reserves. We focus on adding reserve value through the development of our Haynesville Shale acreage and the timely development of our large relatively low risk development program in the East Texas and North Louisiana (ETNL) area. We continue to pursue the acquisition of prospective acreage and oil and gas drilling opportunities.

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

Exploit and Develop Existing Property Base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest production and reserve

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growth potential. We intend to concentrate on developing our multi-year inventory of drilling locations in the Haynesville Shale and Cotton Valley Taylor Sand on our acreage in order to develop our natural gas reserves. We estimate that our Haynesville Shale acreage currently includes as many as 1,500 gross unrisked, non-proved drilling locations based on anticipated well spacing and our Cotton Valley Taylor Sand inventory includes as many as 223 gross unrisked, non-proved drilling locations based on anticipated well spacing.

Transition to Horizontal Drilling. During the past year, the Company has transitioned from a company drilling predominately vertical wells, primarily for the Cotton Valley sands, to one drilling almost exclusively horizontal wells. As such and with the verification of the enhanced economics resulting from its horizontal activities during 2009 for both the Haynesville Shale and Cotton Valley (Taylor) sand, the decision was made to shift away from the vertical drilling of Cotton Valley and Travis Peak wells to a horizontal drilling plan exclusively. Primarily as a result of this strategic decision to change from a vertical to a horizontal drilling plan for developing our existing properties, virtually all of the vertical proved undeveloped and probable locations which had previously been included in our drilling plans were removed.

Expand Acreage Position in the Haynesville Shale and ETNL area. We have increased our acreage position in ETNL to approximately 205,500 gross (137,900 net) acres as of December 31, 2009. 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 in the Haynesville Shale and other plays 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 Low Operating Costs. As we continue to develop our properties, we expect our overall operating costs per Mcfe to continue to decrease, due primarily to an increasing mix of Haynesville Shale production. Production from the Haynesville Shale is not as water-intensive as production from our legacy assets in ETNL thereby reducing our per unit lease operating expenses.

Maintain an Active Hedging Program. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically fixed price swaps and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Use of Advanced Technologies. We continually perform field studies of our existing properties and reevaluate exploration and development opportunities using advanced technologies. For example, we are a member of a consortium that exchanges and analyzes data on Haynesville Shale wells in East Texas and North Louisiana, and we have recently participated in a 3D shoot over a portion of our acreage.

Oil and Gas Operations and Properties

ETNL and Haynesville Shale

Overview. As of December 31, 2009, nearly all of our proved oil and gas reserves were located in East Texas and Northwest Louisiana. We spent nearly all of our 2009 capital expenditures of $237.6 million in this area, with $148.3 million or 62% spent on the Haynesville Shale. Our total capital expenditures, including accrued expenses for services performed during 2009, consist of $215.1 million for drilling and completion costs, $15.8 million for leasehold acquisition, $3.8 million for facilities and infrastructure, $1.9 million for geological and geophysical costs and $1.0 million for furniture, fixtures and equipment.

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As of December 31, 2009, we have acquired or farmed-in leases totaling approximately 205,500 gross (137,900 net) acres and are continually attempting to acquire additional acreage in the area. During 2009, we drilled and completed 45 gross wells in ETNL, including 32 gross Haynesville Shale wells with a 100% success rate. Our current ETNL and Haynesville Shale drilling activities are located in six primary leasehold areas in East Texas and Northwest Louisiana.

The table below details our acreage holdings, average working interest and wells drilled and completed in the ETNL area.

Field or Area	Acreage As of December 31, 2009 Gross	Net	Average Working Interest	Wells Drilled and Completed As of December 31, 2009 Successful	Unsuccessful
North Minden	31,950	27,810	96%	117	2
Beckville	13,410	12,367	100%	82	2
Angelina River	80,829	49,066	64%	94	1
South Henderson	10,614	8,592	100%	37	
Bethany Longstreet	30,556	19,760	70%	71	
Greenwood Waskom Metcalf	4,955	3,382	71%	3	
Longwood	21,364	10,989	60%	28	
Caddo Pine Island	6,400	2,900	43%	5	
Other ETNL	5,374	3,013	68%	19	1
Total ETNL	205,452	137,879	83%	456	6
Other	2,135	227	33%		
Total	207,587	138,106	81%	456	6

In those fields or areas where we have made the determination that the Haynesville Shale is productive, 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, 2009 Gross	Net	Average Working Interest	Wells Drilled and Completed As of December 31, 2009 Successful	Unsuccessful
North Minden	31,830	25,885	100%	7	
Beckville	13,410	11,354	100%	5	
Angelina River	38,876	22,321	50%	2	
South Henderson					
Bethany Longstreet	30,556	13,547	35%	24	
Greenwood Waskom Metcalf	4,955	3,382	71%	3	
Longwood	10,989	4,926	42%	4	
Caddo Pine Island	6,400	2,900	43%	5	
Other	1,919	544	48%		
Total Haynesville Shale (1)	138,935	84,859	55%	50	

(1)

Of the total 50 wells drilled and completed as of December 31, 2009, 12 wells were drilled vertically early in our Haynesville Shale program to confirm the existence of the shale in the related area and were not necessarily meant to most economically develop the field.

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Production and Reserves. Initial production from the horizontally drilled wells in the Haynesville Shale play commenced in January 2009. Gross production averaged approximately 118,000 Mcfe/d and net production averaged approximately 36,000 Mcfe/d for the fourth quarter of 2009. At December 31, 2009, 47% of our proved reserves were attributable to properties with production from the Haynesville Shale.

	December 31, 2009				Fourth Quarter 2009	
Field or Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total	Net Average Daily Production (Mcfe/d)	% of Total
North Minden	36,827	15,985	52,812	13%	16,371	19%
Beckville	38,823	95,966	134,789	32%	16,832	20%
Angelina River	28,283		28,283	7%	14,207	17%
South Henderson	9,927		9,927	2%	4,435	5%
Bethany Longstreet	39,251	134,102	173,353	41%	26,810	31%
Greenwood Waskom Metcalf	5,636	8,989	14,625	3%		
Longwood	2,908		2,908	1%	1,744	2%
Caddo Pine Island	468		468			
Other ETNL	1,895		1,895	1%	5,506	6%
Total ETNL	164,018	255,042	419,060	100%	85,905	100%
Other	1,501		1,501		176	
Total	165,519	255,042	420,561	100%	86,081	100%

Other Properties

In March 2007, we sold substantially all of our oil and gas properties in South Louisiana. The sale resulted in net proceeds of $72.3 million, after normal closing adjustments. We continue to treat the Plumb Bob field in South Louisiana as held for sale, which represents less than 1% of our total equivalent proved reserves at December 31, 2009.

As of December 31, 2009, 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.

Oil and Natural Gas Reserves

In December 2008, the SEC adopted new rules related to modernizing reserve calculation 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 compute depreciation, depletion and amortization. Another significant provision of the new 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.

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The following tables set forth summary information with respect to our proved reserves as of December 31, 2009 and 2008, as estimated by us by compiling reserve information derived from the evaluations performed by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers. A copy of their summary report 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, 2009			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	368	63	446	877
Natural Gas (MMcf)	142,134	20,801	252,366	415,301
Natural Gas Equivalent (MMcfe)	144,343	21,176	255,042	420,561
Estimated Future Net Cash Flows				$ 424,983
Present Value of Future Net Cash Flows (before income taxes) (1)				$ 148,165
Discounted Future Income Taxes				(941)
Standardized Measure of Discounted Net Cash Flows (1)				$ 147,224

	Proved Reserves at December 31, 2008			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls)	316	71	1,596	1,983
Natural Gas (MMcf)	130,746	19,428	240,276	390,449
Natural Gas Equivalent (MMcfe)	132,643	19,852	249,854	402,349
Estimated Future Net Cash Flows				$ 560,007
Present Value of Future Net Cash Flows (before income taxes) (1)				$ 169,844
Discounted Future Income Taxes				(2,401)
Standardized Measure of Discounted Net Cash Flows (1)				$ 167,443

(1) PV-10 represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. Our standard measure of discounted future net cash flows of proved reserves, or standardized measure, as of December 31, 2009 was $147.2 million. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

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

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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 properties, 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 2009 through December 2009, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The average prices used in such estimates were $3.87 per Mmbtu, of natural gas and $57.65 per Bbl of crude oil/condensate. These prices do not include the impact of hedging transactions, nor do they include 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.

Our proved reserve information as of December 31, 2009 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. 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.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserves estimation process. Our technical team meets regularly with representatives of NSAI to review properties and discuss methods and assumptions used in NSAI s preparation of the year-end reserves estimates. 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.

Proved Undeveloped Reserves. Our proved undeveloped reserves at December 31, 2009, as estimated by our independent petroleum consultant, were 255.0 Bcfe, consisting of 252.4 Bcf of natural gas and 0.4 MMBbls of oil and condensate. In 2009, we developed approximately 1% of our total proved undeveloped reserves booked as of December 31, 2008 through the drilling of 4 gross (2.8 net) development wells at an aggregate capital cost of approximately $14.2 million. None of our proved undeveloped reserves at December 31, 2009 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, 2009 reserve report on a date more than five years from the date the reserves were initially booked as proved undeveloped.

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Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2009:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Louisiana	1	0.7	118	66.7	119	67.4
Texas	5	3.4	338	291.9	343	295.3
Michigan and other	1	0.1	3		4	0.1
Total Productive Wells	7	4.2	459	358.6	466	362.8

(1) Does not include royalty or overriding royalty interests.
(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, 95 wells had completions in multiple producing horizons.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2009. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	33,753	19,919	32,744	18,391	66,497	38,310
Texas	95,890	70,002	43,280	29,775	139,170	99,777
Michigan			1,920	19	1,920	19
Total	129,643	89,921	77,944	48,185	207,587	138,106

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 three years at the rate of 5,024 net acres in 2010, 12,426 net acres in 2011 and 4,407 net acres in 2012, unless included in producing units or extended prior to lease expiration.

Operator Activities

We operate a majority of our producing properties by value, and will generally seek to become the operator of record on properties we drill or acquire in the future. 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,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	43	23.6	107	65.9	90	72.0
Non-Productive			2	1.1	1	0.7
Total	43	23.6	109	67.0	91	72.7
Exploratory Wells:						
Productive	2	1.0	17	8.4	5	3.4
Non-Productive						
Total	2	1.0	17	8.4	5	3.4
Total Wells:						
Productive	45	24.6	124	74.3	95	75.4
Non-Productive			2	1.1	1	0.7
Total	45	24.6	126	75.4	96	76.1

At December 31, 2009, the Company had 5 gross (2.4 net) development wells in process of being drilled.

Net Production, Unit Prices and Costs

The following table presents certain information with respect to natural gas and oil production attributable to our interests in all of our fields, the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2009.

	2009	2008	2007
Net Production Continuing Operations:			
Natural gas (MMcf)	28,891	23,174	15,281
Oil and condensate (MBbls)	151	167	118
Total (MMcfe)	29,796	24,176	15,991
Average daily production (Mcfe)	81,632	66,054	43,811

Revenue Continuing Operations (in thousands):			
Natural gas	$ 102,692	$ 199,057	$ 102,215
Oil and condensate	8,092	16,312	8,476
Total	$ 110,784	$ 215,369	$ 110,691
Average Realized Sales Price Per Unit Continuing Operations:			
Natural gas (per Mcf)	$ 3.55	$ 8.59	$ 6.69
Oil and condensate (per Bbl)	$ 53.65	$ 97.70	$ 71.83
Total (per Mcfe)	$ 3.72	$ 8.91	$ 6.92
Other Data Continuing Operations (per Mcfe):			
Lease operating expenses	$ 1.01	$ 1.32	$ 1.40
Production and other taxes	$ 0.14	$ 0.31	$ 0.14
Transportation	$ 0.32	$ 0.36	$ 0.37
Depreciation, depletion and amortization	$ 5.38	$ 4.43	$ 4.99
Exploration	$ 0.31	$ 0.35	$ 0.46
Impairment of oil and gas properties	$ 7.01	$ 1.18	$ 0.48
General and administrative	$ 0.94	$ 1.00	$ 1.31

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For a discussion of comparative changes in our production volumes, revenues and operating expenses for the three years ended December 31, 2009, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operations .

Oil and Gas Marketing and Major Customers

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

Customers. Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from these sources as a percent of oil and gas revenues for the year ended December 31, 2009 was as follows:

	2009
Louis Dreyfus Corporation	32%
Shell Energy	19%
Crosstex Energy	10%

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 24, 2010, we had 125 full-time employees in our two administrative offices and one field office, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection and well testing.

Available Information

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

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*.

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Regulations

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

Environmental Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these laws and regulations may require the acquisition of 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.

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.

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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.

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

The 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. Due to concerns raised concerning potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing. Such efforts could have an adverse effect on our natural gas production activities.

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. We believe our operations are in substantial compliance with applicable air permitting and control technology requirements.

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In response to studies suggesting that emissions of certain gases commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere and other climate changes, President Obama has expressed support for, and Congress is actively considering legislation to restrict or regulate emissions of greenhouse gases by establishing an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap-and-trade programs. Also, the EPA has determined that greenhouse gases present an endangerment to public health and the environment and, consequently, has proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources, as well as adopted regulations requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional, or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance or operating costs or additional operating restrictions, any of which could have a material adverse effect on our business or demand for the oil and gas we produce.

The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. We believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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.

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. We believe that our operations are in substantial compliance with applicable OSHA requirements.

Item 1A. *Risk Factors*

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

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

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

The proved oil and gas reserve information included in this report are estimates. These estimates are based on reports prepared by NSAI, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and gas prices in 2009. These prices will change and may be lower at the

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time of production than those prices that prevailed during 2009. Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

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

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

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

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on 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 estimates of proved reserves have been prepared under new 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, 2009, which have been prepared and presented under new SEC rules. These new 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, 2009 was based on an unweighted average twelve month West Texas Intermediate (WTI) posted price of $57.65 per Bbl for oil and a Henry Hub Spot

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price of $3.87 per MMBtu for natural gas, as compared to $41.00 per Bbl for oil and $5.71 per MMBtu for natural gas as of December 31, 2008. As a result of these changes, direct comparisons to our previously-reported reserves amounts may be more difficult.

Another impact of the new 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 new 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 East Texas and Northwest Louisiana. 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 not reviewed our or any reporting company s reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 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.

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, we recently completed drilling our sixth horizontal well in the ETNL area. We have only limited experience drilling horizontal wells and there can be no assurance that this method of drilling will be as effective as we currently expect it to be.

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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 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, or OPEC, and its maintenance of production constraints, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

Crude oil and natural gas prices are extremely volatile. Average oil and natural gas prices decreased substantially during the year ended December 31, 2009. Any additional actual or anticipated reduction in crude oil and natural gas 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. The following table includes high and low natural gas prices (price per MMBtu) and crude oil prices (WTI) during calendar year 2009, as well as these prices at year-end and at February 24, 2010:

	Henry Hub Per MMBtu
January 6, 2009 (high)	$ 6.10
September 4, 2009 (low)	1.84
December 31, 2009	5.82
February 24, 2010	4.91

	WTI Per barrel
October 21, 2009 (high)	$ 81.03
February 12, 2009 (low)	34.03
December 31, 2009	79.39
February 24, 2010	79.75

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Prices for natural gas and crude oil declined sharply in the second half of 2008 and have remained low when compared with average prices in recent years. These lower prices, coupled with the recent turmoil 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 writedowns. Any such writedown could have a material adverse effect on our results of operations in the period taken.

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A sustained depression of oil and natural gas prices can affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our current credit facility. This may hinder or prevent us from meeting our future capital needs.

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.

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

We use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. We hedged approximately 70% of our total production volumes for the year ended December 31, 2009.

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 oil and natural gas. For the years ended December 31, 2009 and 2007, we realized a gain on settled natural gas derivatives of $98.0 million and $9.7 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, 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.

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

We account for our natural gas 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.

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

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

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 61% of our total estimated proved reserves by volume at December 31, 2009, were undeveloped. By their nature, estimates of undeveloped reserves and timing of their production are less certain. 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 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, 2009, 2008 and 2007, we recorded impairments from continuing operations related to oil and gas properties of $208.9 million, $28.6 million and $7.7 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

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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, 2009, and all our production during 2009 was associated with our ETNL properties which includes the Haynesville Shale. 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 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. Encana Corporation and St. Mary Land and Exploration Company operate certain properties in the ETNL area in which we have an interest. 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.

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 ETNL area, which is in the same geographic region as the recently discovered Haynesville Shale. A number of companies are currently operating in the Haynesville Shale. If drilling in the Haynesville 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 ETNL area 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.

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

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specified financial ratios under the terms of our senior credit facility. As of December 31, 2009, 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 may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities 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.

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

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

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

In addition, our operations are subject to stringent federal, state and local environmental laws and regulations governing the discharge of materials into the environment and environmental protection. Governmental authorities enforce compliance with these laws and regulations and the permits issued under them, which can result in an obligation to undertake difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of our operations. There is inherent risk of incurring significant environmental costs and liabilities in our business. The imposition of strict, and in certain circumstances, joint and several liabilities is common in environmental laws and may result in us incurring costs in connection with discharges or releases of petroleum hydrocarbons and wastes due to our handling of those substances, the release of air emissions or water discharges in connection with our operations, and historical industry operations and waste disposal practices conducted by us or predecessor operators on, under or from our properties and from facilities where our wastes have been taken for recycling or disposal. Private parties affected by such discharges or releases may also have the right to pursue legal actions to enforce compliance as well as seek damages for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly requirements could have a material adverse effect on our business.

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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 crude oil and natural gas that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency (EPA) published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. Also, on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACESA, which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances authorizing emissions of greenhouse gases into the atmosphere. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support for legislation to reduce greenhouse gas emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Federal legislation 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 affect our support services.

Congress is currently considering two companions bills for the Fracturing Responsibility and Awareness of Chemicals Act, or FRAC Act. The bills would repeal an exemption in the federal Safe Drinking Water Act (SWDA) for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. Sponsors of the FRAC Act have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The FRAC Act also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally

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sensitive areas such as watersheds. The adoption of the FRAC Act or any other federal or state laws or regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas wells in shale formations, increase our costs of compliance and doing business.

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

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

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

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

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.

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

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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.

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.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is considering whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Separately, the House of Representatives adopted financial regulatory reform legislation on December 11, 2009, that among other things would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace. This legislation would subject swap dealers and major swap participants to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants, and would provide the CFTC with authority to impose position limits in the OTC derivatives markets. A major swap participant generally would be someone other than a dealer who maintains a substantial net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating

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commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the US banking system or financial markets. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

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

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States 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 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 any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact our financial condition and results of operations with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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

None.

Item 3. ***Legal Proceedings***

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

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

None.

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PART II

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

Market Price of Our Common Stock

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

At February 24, 2010, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,380 with 37,519,966 shares outstanding. High and low sales prices for our common stock for each quarter during the calendar years 2009 and 2008 are as follows:

	2009		2008	
	High	Low	High	Low
First Quarter	$ 34.07	$ 14.93	$ 30.08	$ 18.32
Second Quarter	30.03	19.27	82.92	29.02
Third Quarter	27.56	21.43	80.49	37.05
Fourth Quarter	30.38	20.38	41.84	20.48

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, 2009. When an employee s restricted stock shares vest, the company (at the option of the employee) generally withholds an amount of shares necessary to cover that employees minimum income tax withholding obligation. The company then advances the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2009, we withheld 44,196 shares 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.

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

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

Statement of Operations Data:

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share amounts)				
Revenues:					
Oil and gas revenues	$ 110,784	$ 215,369	$ 110,691	$ 73,933	$ 34,986
Other	(358)	682	614	838	325
	110,426	216,051	111,305	74,771	35,311
Operating Expenses:					
Lease operating expense	30,188	31,950	22,465	12,688	3,494
Production and other taxes	4,317	7,542	2,272	3,345	2,136
Transportation	9,459	8,645	5,964	3,791	558
Depreciation, depletion and amortization	160,361	107,123	79,766	37,225	12,214
Exploration	9,292	8,404	7,346	5,888	5,697
Impairment of oil and gas properties	208,905	28,582	7,696	9,886	340
General and administrative	27,923	24,254	20,888	17,223	8,622
Gain on sale of assets	(297)	(145,876)	(42)	(23)	(235)
Other			109		
	450,148	70,624	146,464	90,023	32,826
Operating income (loss)	(339,722)	145,427	(35,159)	(15,252)	2,485
Other income (expense):					
Interest expense	(26,148)	(22,410)	(17,878)	(8,343)	(2,359)
Interest income	433	2,184			
Gain (loss) on derivatives not designated as hedges	47,115	51,547	(6,439)	38,128	(37,680)
Loss on early extinguishment of debt				(612)	
	21,400	31,321	(24,317)	29,173	(40,039)
Income (loss) from continuing operations before income taxes	(318,322)	176,748	(59,476)	13,921	(37,554)
Income tax (expense) benefit	67,311	(54,472)	9,294	(4,940)	13,144
Income (loss) from continuing operations	(251,011)	122,276	(50,182)	8,981	(24,410)
Discontinued operations including gain on sale of assets, net of income taxes	25	(502)	11,469	(7,660)	6,960
Net income (loss)	(250,986)	121,774	(38,713)	1,321	(17,450)
Preferred stock dividends	6,047	6,047	6,047	6,016	755

Preferred stock redemption premium				1,545	
Net income (loss) applicable to common stock	$ (257,033)	$ 115,727	$ (44,760)	$ (6,240)	$ (18,205)
PER COMMON SHARE					
Income (loss) from continuing operations basic	$ (7.00)	$ 3.61	$ (1.96)	$ 0.36	$ (1.05)
Income (loss) from continuing operations diluted	$ (7.00)	$ 3.24	$ (1.96)	$ 0.35	$ (1.05)
Income (loss) on discontinued operations, net of tax basic	$	$ (0.01)	$ 0.45	$ (0.30)	$ 0.30
Income (loss) on discontinued operations, net of tax diluted	$	$ (0.01)	$ 0.45	$ (0.30)	$ 0.30
Net income (loss) applicable to common stock basic	$ (7.17)	$ 3.42	$ (1.75)	$ (0.25)	$ (0.78)
Net income (loss) applicable to common stock diluted	$ (7.17)	$ 3.23	$ (1.75)	$ (0.25)	$ (0.78)
Weighted average common shares outstanding basic	35,866	33,806	25,578	24,948	23,333
Weighted average common shares outstanding diluted	35,866	40,397	25,578	25,412	23,333

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	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Balance Sheet Data:					
Total assets	$ 860,274	$ 1,038,287	$ 589,233	$ 478,573	$ 296,526
Total long-term debt	330,147	226,723	185,449	165,216	30,000
Stockholders equity	445,385	665,348	312,781	228,026	181,589

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

Forward-Looking Statements

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

- planned capital expenditures;
- future drilling activity;
- our financial condition;
- business strategy;
- the market prices of oil and gas;
- uncertainties about the estimated quantities of oil and natural gas reserves, including uncertainties about the effects of the SEC s new rules governing reserve reporting;
- economic and competitive conditions;
- legislative and regulatory changes;
- financial market conditions and availability of capital;
- production;

hedging arrangements;

future cash flows and borrowings;

litigation matters;

more stringent environmental laws and increased difficulty in obtaining environmental permits;

pursuit of potential future acquisition opportunities; and

sources of funding for exploration and development.

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

These factors, as well as additional factors that could affect our operating results and performance are described in this report under the headings Business, Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations. We urge you to carefully consider those factors.

All forward-looking statements attributable to us are qualified in their entirety by this cautionary statement. We undertake no responsibility to update our forward-looking statements.

Overview

We are an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the ETNL area, which includes the Haynesville Shale play. 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.

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

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

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

East Texas and North Louisiana Area

Our relatively low risk development drilling program in the ETNL area 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 area and hold 205,452 gross acres as of December 31, 2009. As of year end 2009, we drilled and completed a cumulative total of 462 wells in this area with a success rate in excess of 98%. Our net production volumes from our ETNL wells aggregated approximately 81,131 Mcfe per day in 2009, or approximately 99% of our total oil and gas production for the year.

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2009 Haynesville Shale Developments

Company Operated Haynesville Shale Drilling Program

By the end of 2009, we had conducted drilling operations on thirteen operated Haynesville Shale horizontal wells, with average initial 24 hour production rates ranging from 6.5 Mmcfe per day to 22.1 Mmcfe per day. For the last quarter of 2009, net production from our operated Haynesville Shale wells (horizontal and vertical) totaled approximately 15,637 Mcfe per day, or 18.2% of the total company production. We currently anticipate drilling approximately 20 operated Haynesville Shale horizontal wells in 2010.

Chesapeake Haynesville Shale Joint Development

Through our joint development arrangement with Chesapeake Energy Corporation (Chesapeake), which covers certain of our acreage in northwest Louisiana, we continue to operate existing production and operate any new wells drilled to the base of the Cotton Valley sand, and Chesapeake will operate any wells drilled below the base of the Cotton Valley sand, including the Haynesville Shale. As of December 31, 2009, we participated in drilling operations on 24 horizontal and 1 vertical Haynesville wells under the joint development arrangement. As of year-end, 17 horizontal and 1 vertical wells had reached initial production and the remaining 7 horizontal wells were in some form of drilling or completion. For 2010, we and Chesapeake plan to utilize three to four rigs to conduct drilling operations on approximately 20 to 30 gross additional Haynesville Shale horizontal wells.

Company Operated Cotton Valley Taylor Sand Program

During 2009 we commenced a horizontal drilling program targeting the Cotton Valley Taylor Sand (CVTS). By the end of the year we had drilled and completed four horizontal CVTS wells in East Texas, with average initial 24 hour production rates ranging from 4.0 Mmcfe per day to 7.0 Mmcfe per day. For the fourth quarter, net production from these four operated wells was approximately 4,577 Mcfe per day. We anticipate drilling approximately four CVTS wells in 2010.

Overview of 2009 Results

- We achieved annual production volume growth of 23% with production volume growing from 24.2 Bcfe in 2008 to 29.8 Bcfe in 2009.

- We increased our ownership in the Haynesville Shale play in Northwest Louisiana and East Texas to approximately 85,000 net acres at December 31, 2009.

- We drilled and completed 45 gross (25 net) wells in 2009, as compared to 126 gross (75 net) wells in 2008.

We raised $218.5 million from our 5% convertible senior note offering in September 2009, the proceeds of which we paid down all of the outstanding borrowings under our senior credit facility and paid off our $75.0 million second lien term loan. We ended the year with $125.1 million in cash and short term investments.

Estimated proved reserves grew 5% to approximately 420.6 Bcfe (approximately 415.3 Bcf of natural gas and 0.9 MMBbls of oil and condensate), with a PV-10 of $148.2 million (before discounted future income taxes of $1.0 million) and a standardized measure of $147.2 million, approximately 39% of which is proved developed.

Capital expenditures totaled $237.6 million in 2009, versus $380.1 million in 2008.

Net cash provided by operating activities increased $8.5 million from 2008, to $115.6 million in 2009.

We reduced our lease operating expenses by $0.31 per Mcfe to $1.01 per Mcfe in 2009, from $1.32 per Mcfe, in 2008.

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Summary Operating Information:	**Year End December 31,**				**Year End December 31,**			
Continuing Operations	**2009**	**2008**	**Variance**		**2008**	**2007**	**Variance**	
			(In thousands, except for price data)					
Revenues:								
Natural gas	$ 102,692	$ 199,057	$ (96,365)	(48%)	$ 199,057	$ 102,215	$ 96,842	95%
Oil and condensate	8,092	16,312	(8,220)	(50%)	16,312	8,476	7,836	92%
Natural gas, oil and condensate	110,784	215,369	(104,585)	(49%)	215,369	110,691	104,678	95%
Operating revenues	110,426	216,051	(105,625)	(49%)	216,051	111,305	104,746	94%
Operating expenses	450,148	70,624	379,524	537%	70,624	146,464	(75,840)	(52%)
Operating income (loss)	(339,722)	145,427	(485,149)	(334%)	145,427	(35,159)	180,586	514%
Net income (loss) applicable to common stock	(257,033)	115,727	(372,760)	(322%)	115,727	(44,760)	160,487	359%
Net Production:								
Natural gas (MMcf)	28,891	23,174	5,717	25%	23,174	15,281	7,893	52%
Oil and condensate (MBbls)	151	167	(16)	(10%)	167	118	49	42%
Total (MMcfe)	29,796	24,176	5,620	23%	24,176	15,991	8,185	51%
Average daily production (Mcfe/d)	81,632	66,054	15,578	24%	66,054	43,811	22,243	51%
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$ 3.55	$ 8.59	$ (5.04)	(59%)	$ 8.59	$ 6.69	$ 1.90	28%
Oil and condensate (per Bbl)	53.65	97.70	(44.05)	(45%)	97.70	71.83	25.87	36%
Average realized price (per Mcfe)	3.72	8.91	(5.19)	(58%)	8.91	6.92	1.99	29%

Results of Operations

For the year ended December 31, 2009, we reported net loss applicable to common stock of $257.0 million, or $7.17 per share (basic and diluted), on oil and gas revenues from continuing operations of $110.8 million. This compares to 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, and a net loss applicable to common stock of $44.8 million, or $1.75 per share (basic and diluted) for the year ended December 31, 2007.

2009 financial and operating results include:

In conjunction with the decline in natural gas prices during 2009, we recorded a $47.8 million gain on natural gas derivatives not designated as hedges for the year ended December 31, 2009. This includes a realized gain of $98.0 million and an unrealized loss of $50.2 million.

We recorded an impairment on continuing operations of $208.9 million.

Our income tax benefit for the year was decreased by $54.3 million as a result of an increase in our valuation allowance related to our deferred tax assets. See Note 6 Income Taxes to our consolidated financial statements.

Operating Income

Year ended December 31, 2009 compared to year ended December 31, 2008

Revenues from continuing operations decreased $105.6 million or 49% to $110.4 million in 2009 compared to $216.1 million in 2008, primarily due to a 58% decrease in the average realized sales price offset somewhat by a net production increase of 23%.

Oil and gas revenues from continuing operations decreased $104.6 million to $110.8 million in 2009, a decrease of 49% from 2008. The oil and gas revenue reduction attributed to the realized price decrease was $125.5 million while the increase in production offset that decrease by $20.9 million. Our average realized sales price was $3.72 per

Mcfe in 2009 compared to $8.91 per Mcfe in 2008. Sales prices are dictated by the market, thus we have very little control over them. 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 the ETNL 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 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 expenses of $241.5 million in 2009 increased 29% or $53.6 million over operating expenses of $187.9 million in 2008. This increase is primarily attributed to increased depreciation, depletion and amortization (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, 2008 compared to year ended December 31, 2007

Revenues from continuing operations increased 94% compared to 2007, to a total of $216.1 million in 2008 due to a 51% increase in production and a 29% increase in the average realized price. Production increased year-to-year from 15,991 MMcfe to 24,176 MMcfe and our average realized price increased from $6.92 per Mcfe to $8.91 per Mcfe. The drilling and completion of 126 wells in the ETNL area resulted in the continued natural gas production growth for the company even though we estimate we curtailed approximately 300 MMcfe of natural gas production in September 2008 as a result of Hurricane Ike. Operating expenses of $70.6 million for the year ended December 31, 2008, include the $145.9 million gain on sale of assets as a reduction in operating expenses and impairment expense of $28.6 million. Excluding the gain on sales of assets for 2008 and impairment expense for both 2008 and 2007, operating expenses of $187.9 million increased 35% or $49.1 million over 2007 operating expenses of $138.8 million (not including $7.7 million of impairment expense). This increase is a direct result of increased production from year-to-year. Although revenues were up significantly for the full year, we experienced a substantial reduction in revenues in the last half of 2008 versus the first half of the year, due to the substantial oil and natural gas price declines.

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Operating Expenses

	Year Ended December 31,				Year Ended December 31,			
Operating Expenses (in thousands)	**2009**	**2008**	**Variance**		**2008**	**2007**	**Variance**	
Lease operating expenses	$ 30,188	$ 31,950	$ (1,762)	(6%)	$ 31,950	$ 22,465	$ 9,485	42%
Production and other taxes	4,317	7,542	(3,225)	(43%)	7,542	2,272	5,270	232%
Transportation	9,459	8,645	814	9%	8,645	5,964	2,681	45%
Depreciation, depletion and amortization	160,361	107,123	53,238	50%	107,123	79,766	27,357	34%
Exploration	9,292	8,404	888	11%	8,404	7,346	1,058	14%
Impairment	208,905	28,582	180,323	631%	28,582	7,696	20,886	271%
General and administrative	27,923	24,254	3,669	15%	24,254	20,888	3,366	16%

	Year Ended December 31,				Year Ended December 31,			
Operating Expenses per Mcfe	**2009**	**2008**	**Variance**		**2008**	**2007**	**Variance**	
Lease operating expenses	$ 1.01	$ 1.32	$ (0.31)	(23%)	$ 1.32	$ 1.40	$ (0.08)	(6%)
Production and other taxes	0.14	0.31	(0.17)	(55%)	0.31	0.14	0.17	121%
Transportation	0.32	0.36	(0.04)	(11%)	0.36	0.37	(0.01)	(3%)
Depreciation, depletion and amortization	5.38	4.43	0.95	21%	4.43	4.99	(0.56)	(11%)
Exploration	0.31	0.35	(0.04)	(11%)	0.35	0.46	(0.11)	(24%)
Impairment of oil and gas properties	7.01	1.18	5.83	494%	1.18	0.48	0.70	146%
General and administrative	0.94	1.00	(0.06)	(6%)	1.00	1.31	(0.31)	(24%)

Year ended December 31, 2009 compared to year ended December 31, 2008

Lease operating expense (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. We expect the LOE per unit of production to continue to decrease as a result of increasing our production from the Haynesville Shale.

Production and other taxes for the year 2009 were $4.3 million which includes 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 Tight Gas Sands (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. 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 horizontally drilled 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.

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Ad valorem taxes increased $1.0 million to $3.0 million in 2009 from $2.0 million in 2008. 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. 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 year-to-year.

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.

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. While this internal reserve report was prepared in accordance with existing SEC guidelines, it 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. The reserve estimates from this 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.

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.

We recorded an impairment of $208.9 million in 2009 on several of our 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 is deemed no longer the most economic avenue to pursue. As a result, the carrying value of our oil and gas assets exceeded their fair value as of December 31, 2009 by an additional $185.4 million versus the last impairment test, which was run as of June 30, 2009. Thus, the total impairment charge for the year was $208.9 million, with the incremental $185.4 million in charges taken at year end being spread across the following fields in North Louisiana and East Texas: Bethany Longstreet ($46.5 million), Bethune/East Gates ($33.6 million), Loco Bayou ($35.0 million), Cotton South/Raintree ($51.9 million), and a collection of other fields ($18.4 million). In all of these cases, the impairment charges were driven by the removal of the previously scheduled vertical proved and probable drilling locations and were partially offset by the addition of horizontal undeveloped locations in fields where such locations were deemed appropriate. We recorded impairment expense of $28.6 million in 2008, related to the Brachfield, Blocker, Alabama Bend and Gilmer Fields, which are located in non-core areas in North Louisiana and East Texas.

General and administrative (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.

Year ended December 31, 2008 compared to year ended December 31, 2007

LOE decreased $0.08 per Mcfe, or 6%, on a per unit basis compared to 2007. Production gains of 51% year-over-year offset the impact of generally higher costs. On an absolute dollar basis, LOE increased $9.5 million or 42% for 2008 as compared to 2007. The largest cost components of LOE for 2008 include salt water disposal (SWD) costs of $9.7 million, compressor rental costs of $6.6 million and LOE for properties operated by others (Non-Op) of $2.0 million. SWD and compressor rental costs tend to fluctuate with production. As a result of increased production, SWD increased $3.0 million in 2008 ($9.7 million or $0.40 per Mcfe for 2008 versus $6.7 million or $0.42 per Mcfe for 2007). Compressor rental costs increased $2.1 million in 2008 ($6.6 million or $0.27 per Mcfe for 2008 versus $4.5 million or $0.28 per Mcfe for 2007). Both of these cost areas were relatively flat on a per Mcfe basis. Non-Op LOE also increased $1.1 million ($2.0 million or $0.08 per Mcfe for 2008 versus $0.9 million or $0.06 per Mcfe for 2007) due to a greater number of our properties being operated by others. The remaining $3.3 million increase year-to-year represents the increased cost of labor, services and chemicals partially offset by lower workover costs. Workover costs represented $0.16 per Mcfe of the LOE rate for 2007, while workover costs only represented $0.06 per Mcfe of the LOE rate for 2008, due to fewer workover projects slated for 2008.

Production and other taxes of $7.5 million for 2008 include production tax of $5.5 million and ad valorem tax of $2.0 million. For 2007, production and other taxes of $2.3 million include production tax of $1.1 million and ad valorem tax of $1.2 million. Production tax for 2008 is net of $3.2 million of accrued Tight Gas Sands (TGS) credits for our wells in the State of Texas, which credits equate to $0.13 per Mcfe of production. This compares to TGS credits of $3.9 million for 2007. These TGS credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we have been notified of the State s approval. We also anticipate lower production tax rates in the future as we continue to add qualifying wells to our production base and as credits are approved. Production taxes are higher for 2008 as the result of a 51% increase in production over 2007, as well as the higher prices received during the year.

Ad valorem taxes increased to $2.0 million for 2008 from $1.2 million for 2007. 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. The number of properties we owned increased from January 1, 2007 to January 1, 2008 and the assessed values for our existing properties were higher year-to-year. The combination of these two factors led to the increase in ad valorem taxes year-to-year.

Transportation expense increased 45% to $8.6 million in 2008 compared to $6.0 million in 2007, as a result of a 51% increase in production year-to-year. The rate per Mcfe decreased slightly to $0.36 per Mcfe in 2008 from $0.37 the prior year.

DD&A expense increased to $107.1 million in 2008 from $79.8 million in 2007 due to a 51% increase in production year-to-year. The DD&A rate declined from $4.99 per Mcfe for 2007 to $4.43 per Mcfe for 2008. We calculated the first and second quarter 2008 DD&A rates using the December 31, 2007 reserves. During the third quarter of 2008, we engaged an independent engineering firm to fully engineer our June 30, 2008 proved reserve estimates. The mid-year reserve report was used to calculate the rate for the third and fourth quarters of 2008. The DD&A rate per Mcfe based on this report resulted in a DD&A rate of $4.17 per Mcfe and $4.11 per Mcfe for the third and fourth quarters of 2008, respectively. These rates are lower than the rates used for the first half of 2008 due to the cost effective drilling of wells in the first six months of 2008. We engaged the same firm to prepare a mid-year reserve report in 2007 as well as year-end reports since 2005.

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Exploration expense for 2008 increased to $8.4 million from $7.3 million for 2007. The primary component of exploration expense for us is the amortization of undeveloped leasehold costs, which represented $5.8 million of the total. Exploration expenses on a per unit basis declined by 24% from $0.46 per Mcfe for 2007 to $0.35 per Mcfe for 2008. Exploration expenses include $0.3 million for exploratory dry hole costs.

We recorded impairment expense of $28.6 million in 2008, $27.5 million in connection with our independent engineer s report on our reserves as of December 31, 2008. The expense relates to the Brachfield, Blocker, Alabama Bend and Gilmer Fields, which are located in non-core areas in North Louisiana and East Texas. We recorded an impairment expense of $7.7 million in 2007 for our Alabama Bend field and two wells in a non-core area of East Texas.

General and administrative (G&A) expense increased 16% to $24.3 million for 2008 compared to $20.9 million for 2007. G&A on a per unit basis decreased 24% to $1.00 per Mcfe resulting from a 51% increase in production volumes in 2008 as compared to 2007. This increase in costs results from a 33% increase in the number of employees from 86 at December 31, 2007 to 114 at December 31, 2008. Share based compensation expense, which is a non-cash item, amounted to $5.5 million in 2008 compared to $5.3 million for 2007.

Other Income (Expense)

	Year Ended December 31,		
	2009	**2008**	**2007**
		(In thousands)	
Other Income (Expense):			
Interest expense	$ (26,148)	$ (22,410)	$ (17,878)
Interest income	433	2,184	
Gain (loss) on derivatives not designated as hedges	47,115	51,547	(6,439)
Income tax benefit (expense)	67,311	(54,472)	9,294
Gain on disposal, net of tax		29	9,662
Income (loss) from discontinued operations, net of tax	25	(531)	1,807
Average funded borrowings adjusted for debt discount	268,000	244,401	204,412
Average funded borrowings	304,211	271,321	239,275

Year ended December 31, 2009 compared to December 31, 2008

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 (primarily related to the amortization of debt discount on our convertible notes) while interest expense in 2008 included non-cash charges of $8.5 million.

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. The income earned on these investments during 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 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. As a comparison, 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 as we do not designate these contracts as hedges.

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 for 2009 from discontinued operations was less than $0.1 million. We increased our valuation allowance and reduced our net deferred tax asset to zero at December 31, 2009 after considering all available positive and negative evidence related to the realization of our deferred tax asset. Income tax expense on continuing operations was $54.5 million for the year ended December 31, 2008 and an income tax benefit of $0.3 million related to discontinued operations. 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 from continuing operations before taxes of $176.7 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 is to reduce income tax expense for 2008.

Year ended December 31, 2008 compared to December 31, 2007

Interest expense increased by $4.5 million, or 25%, to $22.4 million for 2008 compared to $17.9 million for 2007 as a result of a higher average level of borrowings in 2008, and a slightly higher weighted average interest rate. We added a second lien term loan in January 2008 for $75.0 million, which carries a higher interest rate than both our Senior Credit Facility and our 3.25% convertible senior notes. In July 2008, we paid off all amounts outstanding under our Senior Credit Facility with the proceeds from the sale of assets and an equity offering. We ended the year with no amounts outstanding under our Senior Credit Facility.

We invested 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 newly implemented Short Term Investment Policy. The income earned on these investments during 2008 is reflected in the Interest income line.

Gain on derivatives not designated as hedges was $51.5 million for 2008, including a realized loss of $1.8 million and an unrealized gain of $55.4 million for the change in fair value of our natural gas commodity contracts. The decrease in natural gas prices experienced during the last half of 2008 led to substantial unrealized gains on our commodity contracts. The 2008 gain also includes a realized loss of $0.7 million and an unrealized loss of $1.4 million on our interest rate swap. As a comparison, 2007 includes an unrealized loss of $15.6 million for the changes in fair value of our commodity contracts, a realized gain of $9.5 million and a loss of $0.3 million on our interest rate swap. We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts as we do not designate these contracts as hedges.

In July 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 from continuing operations before taxes of $176.7 million for 2008. As a result, we released $15.3 million of our previously booked valuation allowance in the third quarter of 2008. The impact of this is to reduce income tax expense for the year to a total of $54.2 million. Primarily as a result of the Chesapeake sale, our 2008 income tax liability to the State of Louisiana is $10 million, which is included in the total of $54.2 million.

In a sale that closed March 20, 2007, we sold our assets in South Louisiana to a private company. We realized a gain of $9.7 million, net of tax, in 2007. In August 2008, we closed on the sale of our St. Gabriel field to a private company for $0.1 million. Also in August 2008, we assigned our rights in the Bayou Bouillon field to a private party for a nominal amount. We continue to hold our interests in the Plumb Bob field. Loss from discontinued operations, net of tax of $0.5 million for 2008 includes an impairment of our Plumb Bob field for $1.2 million before tax ($0.8 million net of tax) in connection with our independent engineer s report on reserves as of December 31, 2008.

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Liquidity

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

drilling and completing new natural gas and oil wells;

constructing and installing new production infrastructure;

acquiring and maintaining our lease position, specifically in the ETNL area;

plugging and abandoning depleted or uneconomic wells.

Our preliminary capital budget for 2010 is $255 million. We continue to evaluate our capital budget throughout the year based in part upon availability of capital, status of our drilling operations and the outlook for oil and natural gas prices.

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, 2009 (in thousands). In addition to the contractual obligations presented in the table, our Consolidated Balance Sheet at December 31, 2009 reflected accrued interest on our bank debt of $3.3 million payable in the first quarter of 2009. 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**	**2010**	**2011**	**2012**	**2013**	**2014 and After**
Contractual Obligations							
Long term debt (1)	4	$ 393,500	$	$ 175,000	$	$	$ 218,500
Interest on convertible senior notes	4	62,796	16,613	16,139	10,925	10,925	8,194
Office space leases	10	10,217	1,003	1,010	1,044	1,142	6,018
Office equipment leases	10	656	286	212	63	59	36
Drilling rigs & operations contracts	10	53,520	33,583	10,947	7,945	1,045	
Transportation contracts	10	360	360				
Total contractual obligations (2)		$ 521,049	$ 51,845	$ 203,308	$ 19,977	$ 13,171	$ 232,748

(1) The $175.0 million 3.25% convertible senior notes have a provision at the end of years 5, 10 and 15, for the investors to demand payment on these dates; the first such date is December 1, 2011. 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 $18.3 million. The Company records a separate liability for the fair value of this asset retirement obligation. See Note 3 Asset Retirement Obligation to our consolidated financial statements.

Capital Resources

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations and borrowings under our 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.

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At December 31, 2009, we had no borrowings outstanding under our senior credit facility, providing us with borrowing capacity of $175 million. Our primary sources of cash during 2009 were from net proceeds 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 $12.4 million for interest and $1.4 million for income taxes in 2009. The table below summarizes the sources of cash during 2009, 2008 and 2007:

Cash flow statement information:	Year Ended December 31, 2009	Year Ended December 31, 2008	Variance	Year Ended December 31, 2008	Year Ended December 31, 2007	Variance
	(In thousands)					
Net Cash:						
Provided by operating activities	$ 115,570	$ 107,039	$ 8,531	$ 107,039	$ 85,925	$ 21,114
Used in investing activities	(265,587)	(187,786)	(77,801)	(187,786)	(219,193)	31,407
Provided by financing activities	127,585	223,847	(96,262)	223,847	131,532	92,315
Increase (decrease) in cash and cash equivalents	$ (22,432)	$ 143,100	$ (165,532)	$ 143,100	$ (1,736)	$ 144,836

At December 31, 2009, we had working capital of $102.6 million and long-term debt net of debt discount of $330.1 million. Our working capital position is primarily due to the remaining cash received from the issuance of our 5% convertible senior notes in September 2009.

Cash Flows

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

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 $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 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, 2009.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007

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 $107.0 million, an increase of $21.1 million, or 25%, from $85.9 million in 2007. Our operating revenues increased 94% in 2008 with a 51% increase in average daily production and a 29% increase in commodity prices as compared to 2007.

Investing activities. Net cash used in investing activities was $187.8 million for the year ended December 31, 2008, compared to $219.2 million for 2007. We received net proceeds of $175.1 million from sale of assets (primarily the Chesapeake transaction) compared to net proceeds of $72.3 million received from the sale of substantially all of our South Louisiana assets in 2007. Total capital expenditures of $362.8 million for 2008 increased $71.3 million from $291.5 million in 2007. We conducted drilling and completion operations on 126 gross wells in 2008 compared to 104 gross wells in 2007, an increase of 21%. Of the $362.8 million invested this year, 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. We spent $273.8 million for drilling and completion activities and $14.3 million for facility installation activities in the ETNL area in 2007.

Financing activities. Net cash provided by financing activities was $223.8 million for 2008, an increase of $92.3 million over 2007. In January 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. In July 2008, we 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 have zero borrowings outstanding under our Senior Credit Facility as of December 31, 2008.

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. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of, the borrowing base. The initial borrowing base was established at $175 million. 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 London Interbank Offered Rate (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 each 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 $175.0 million of our 3.25% convertible senior notes due 2026 or the 5% convertible notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. We currently have no amounts outstanding under the credit facility which has a borrowing base of $175.0 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 3.0/1.0 for the trailing four quarters; and

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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).

We are in compliance with all the financial covenants of the Senior Credit Facility as of December 31, 2009.

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 Notes) due in December 2026. The notes mature on December 1, 2026, 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 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. 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 our 3.25% convertible senior notes due 2026 in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods (see Note 1). 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, 2009, the $175.0 million notes were carried on the balance sheet at $159.1 million with a debt discount balance of $15.9 million. As of December 31, 2008, the $175.0 million notes were carried on the balance sheet at $151.7 million with a debt discount of $23.3 million. The remaining amount of debt discount as of December 31, 2009 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 these notes for the years ended December 31, 2009, 2008 and 2007 was $13.9 million, $13.3 million and $12.8 million, respectively. The effective interest rate on the liability component of the notes was 9% for each of the years 2009, 2008 and 2007.

Share Lending Agreement

In connection with the offering of the 3.25% Convertible Senior Notes Due 2026 we agreed to lend 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 the shares and use the sale to

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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 pursuant to the terms of the indenture governing the notes.

The Share Lending Agreement also requires BSC to post collateral of our common stock 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. (JP Morgan Chase) completed its acquisition of The Bear Stearns Companies Inc. JP Morgan Chase credit rating exceeds that required by the Share Lending Agreement. Thus, collateral is no longer required. Should JP Morgan Chase 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, 2009, under the Share Lending Agreement 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.

5% Convertible Senior Notes Due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes due in October 2029. 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. 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 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 (see Note 1 to our consolidated financial statements). 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, 2009 was $5.0 million. The effective rate on the liability component of the notes was 11.2% in the year 2009.

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 JP Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. One-third of the options were scheduled to expire over each of three separate multi-day settlement periods beginning approximately 18 months, 24 months and 30 months from the closing of the offering, respectively. During 2009, two-thirds of the options expired and the company received 266,240 shares back from the counterparties in conjunction with the expirations.

The capped call option transactions are expected to result in our receipt, on a net share, cashless basis of a certain number of shares of our common stock if the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for the relevant tranche is greater than the lower call strike price of the capped call option transactions. We refer to the amount by which the market value per share exceeds the lower call strike price as an in-the-money amount for the relevant tranche of the capped call option transaction. The in-the-money amount will never exceed the difference between the upper call strike price and the lower call strike price (i.e., it will be capped). The lower call strike price is $23.50, which corresponds to the price to the public in the equity offering and the upper call strike price is $32.90, which corresponds to 140% of the price to the public in the offering. Both lower and upper call strike prices are subject to customary anti-dilution and certain other adjustments. The number of shares of our common stock that we will receive from the option counterparties upon expiration of each tranche of the capped call option transactions will be equal to the in-the-money amount of that tranche divided by the market value per share of the common stock, as measured under the terms of the capped call option agreements, on the option expiration date for that tranche. During 2009, two-thirds of the options expired and the company received 266,240 shares based on the share price on the expiration dates. The remaining one-third of the options subject to the capped call will expire in May and June of 2010.

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

The capped call option agreements require an option counterparty to transfer their rights and obligations within 30 days if their credit rating is below either Baa1 by Moody s or BBB+ by S&P. As a result of the ratings downgrade of BSC on March 14, 2008, BSC was obligated to transfer their rights and obligations under the capped call option agreement to a suitable counterparty (one with a credit rating of at least BBB+ by S&P and Baa1 by Moody s within 30 days). BSC s obligation to transfer its rights and obligations to an entity with a higher credit rating was cured by a ratings upgrade on March 24, 2008.

During the second quarter of 2008, BSC sold its position in the capped call options to Bank of America.

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.

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Short Term Investments

The net proceeds from our July 2008 equity offering, the net proceeds from sale of assets in 2008 and the proceeds of our 2009 debt offering were invested in short term investments. As of December 31, 2009, our short term investments amounted to $117.5 million. Prior to making these investments, our board of directors instituted a short term investment policy, to be implemented by our Chief Executive Officer and Chief Financial Officer. The short term investment policy was adopted to meet the following objectives:

Preserve principal;

Maintain liquidity;

Diversify investment risk; and

Maximize earnings on surplus funds consistent with the first three objectives.

This policy also authorizes transactions only with institutions that meet the following criteria:

Short-term debt ratings of at least A1 by S&P and P1 by Moody s;

Long-term debt ratings of at least AA- by S&P or Aa3 by Moody s; and

Market capitalization of at least $25.0 billion for the parent company at the time of the transaction.

Also, funds on deposit at any one institution shall not exceed $100.0 million, unless previously approved by our Chief Financial Officer and Chief Executive Officer.

As of December 31, 2009, we held short term investments in money market funds with three institutions meeting all of these criteria. Short term investments as of December 31, 2009, carried maturities of fourteen days or less and are considered cash equivalents. We will continue to monitor these institutions in light of the current financial market crisis and in accordance with our policy.

Preferred Stock

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

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

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

If a fundamental change occurs, holders may require us in specified circumstances to repurchase all or part of the Series B Convertible Preferred Stock. In addition, upon the occurrence of a fundamental change or

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specified corporate events, we will under certain circumstances increase the conversion rate by a number of additional shares of Common Stock. A fundamental change will be deemed to have occurred if any of the following occurs:

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

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

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

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

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 to our consolidated financial statements.

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.

In addition, the SEC has not reviewed our or any reporting company s reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 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.

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Successful Efforts Accounting

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

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 fair value, using 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. 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

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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 at fair value and recognize as compensation expense over the requisite period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero. 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***

Commodity Price Risk

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

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We enter into futures contracts or other hedging agreements from time to time to manage the commodity price risk for a portion of our production. We do not designate our derivative contracts as hedges accordingly changes in fair value are reflected in earnings. Our strategy, which is administered by the Hedging Committee of the Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our production. As of December 31, 2009, the commodity hedges we use were in the form of:

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

(b) collars, where we receive the excess, if any, of the floor price over the reference price, based on NYMEX quoted prices, and pay the excess, if any, of the reference price over the ceiling price.

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Average Floor/Cap**			**Fair Value at December 31, 2009**
Natural gas (MMBtu)						$ 8,351,279
1Q 2010	50,000	4,500,000	$	6.00	$7.10	
2Q 2010	50,000	4,550,000	$	6.00	$7.10	
3Q 2010	50,000	4,600,000	$	6.00	$7.10	
4Q 2010	50,000	4,600,000	$	6.00	$7.10	
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	
Basis Swaps (NYMEX/TexOk)			**Average Price (1)**			
Natural gas (MMBtu)						$ (3,226,100)
1Q 2010	50,000	4,500,000	$ 0.368			
2Q 2010	50,000	4,550,000	$ 0.368			
3Q 2010	50,000	4,600,000	$ 0.368			
4Q 2010	50,000	4,600,000	$ 0.368			
					Total	$ 5,125,179

(1) Basis swap whereby we receive NYMEX index less a contract price per MMBtu and pay Natural Gas Pipeline of America, TexOk zone price per MMBtu as published in the Inside FERC.

Our hedging contracts fall within our targeted range of 30% to 70% of our estimated net oil and gas production volumes for the applicable periods of 2010 to 2012. The fair value of the natural gas hedging contracts in place at December 31, 2009, resulted in a current asset of $5.4 million and a long term liability of $0.3 million. Based on gas pricing in effect at December 31, 2009, a hypothetical 10% increase in gas prices would have resulted in a current derivative liability of $17.7 million while a hypothetical 10% decrease in gas prices would have increased the current derivative asset to $28.4 million.

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Interest Rate Risk

We have a variable-rate debt obligation that exposes us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. At December 31, 2009, we had the following interest rate swaps in place with BNP Paribas and Bank of Montreal:

Effective Date	Maturity Date	Libor Swap Rate	Notional Amount (Millions)	Fair Value (Dollars)
4/22/2008	4/22/2010	3.191%	$ 25.0	$ (363,065)
4/22/2008	4/22/2010	3.191%	50.0	(723,977)
				$ (1,087,042)

The fair value of the interest rate swap contracts in place at December 31, 2009, resulted in a current liability of $1.1 million. Based on interest rates at December 31, 2009, a hypothetical 10% increase or decrease in interest rates would not have had a material effect on the liability.

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

The information required here is included in this report as set forth in the Index to Consolidated Financial Statements on page F-1.

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

None.

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

Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

As required by SEC rule 13a-15(b), we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of December 31, 2009, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009, is set forth on page F-2 of this Annual Report on Form 10-K and is incorporated by reference herein.

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Ernst & Young LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009, as stated in their report which is included herein on page F-3.

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 26, 2010, are as follows:

Name	Age	Position
Patrick E. Malloy, III	67	Chairman of the Board of Directors
Walter G. Gil Goodrich	51	Vice Chairman, Chief Executive Officer and Director
Robert C. Turnham, Jr.	52	President, Chief Operating Officer and Director
David R. Looney	53	Executive Vice President and Chief Financial Officer
Mark E. Ferchau	55	Executive Vice President
Michael J. Killelea	47	Senior Vice President, General Counsel and Corporate Secretary
Henry Goodrich	79	Chairman Emeritus and Director
Josiah T. Austin	63	Director
Geraldine A. Ferraro	74	Director
Michael J. Perdue	55	Director
Arthur A. Seeligson	51	Director
Stephen M. Straty	54	Director
Gene Washington	63	Director

Josiah T. Austin has served as one of our directors since August 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 May 2004.

Mark E. Ferchau has served as an Executive Vice President since April 2004. He originally joined us in September 2001, and from February 2003 to April 2004 he served as our Senior Vice President, Engineering and Operations. Mr. Ferchau has over 25 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 August 2003. Ms. Ferraro was a principal in the government relations practice of Blank Rome LLP, a national law firm from February 2007 until her retirement on January 31, 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 August 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 August 1995. He became Vice Chairman of our Board in February 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.

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Michael J. Killelea joined us as Senior Vice President, General Counsel and Corporate Secretary in January 2009. Mr. Killelea has over 20 years of experience in the energy industry. From June 2008 through November 2008, he served as Vice President, 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 March 2000 until the sale of Pogo Producing Company to Plains Exploration Company in November 2007.

David R. Looney joined us as Executive Vice President and Chief Financial Officer in May 2006. Mr. Looney has over 30 years of experience in the energy finance business, most recently as Executive Vice-President and Chief Financial Officer of Energy Partners, Ltd., a publicly traded exploration and production company, from March 2005 to April 2006 and Vice-President, Finance and Treasurer of EOG Resources, Inc., one of the largest publicly traded exploration and production companies in the U.S., from August 1999 to February 2005.

Patrick E. Malloy, III has served as one of our directors since May 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 January 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 October 2006, Mr. Perdue served as President and Chief Executive Officer of Community Bancorp Inc., from July 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 August 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.

Stephen M. Straty has served as one of our directors since January 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 June 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 December 2006. Mr. Turnham joined Goodrich as Chief Operating Officer in August 1995 and became President and Chief Operating Officer in February 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 June 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 2010 Annual Meeting of Stockholders. Additional information regarding our corporate governance guidelines as well as the complete texts of its Code of Business Conduct and Ethics and the charters of our Audit Committee, Compensation Committee and our Nominating and Corporate Governance Committee may be found on our website at *www.goodrichpetroleum.com.*

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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 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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PART IV

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

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

See Index to Consolidated Financial Statements on page F-1.

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

3.1	Restated Certificate of Incorporation of Goodrich Acquisition II, Inc. dated January 31, 1997 (Incorporated by reference to Exhibit 3.1 A of the Company s Third Amended Registration Statement on Form S-1 (Registration No. 333-47078) filed on December 8, 2000).
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).
4.3	Registration Rights Agreement dated December 6, 2006 among Goodrich Petroleum Corporation, Bear, Sterns & Co. Inc., Deutsche Bank Securities Corp. and BNP Paribas Securities Corp (Incorporated by reference to Exhibit 4.11 of the Company s Annual Report on Form 10-K (File No. 001-12719) for the year ended December 31, 2006).
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).

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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).
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).

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10.16	Amended and Restated Severance Agreement between the Company and David R. Looney dated November 5, 2007 (Incorporated by reference to Exhibit 10.3 of the Company s Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 8, 2007).
10.17	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).
10.18	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).
10.19	First Amendment to 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).
10.20	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).
10.21	Capped Call Option Confirmation among Goodrich Petroleum Corporation and Bear Stearns International Limited, dated December 4, 2007 (Incorporated by reference to Exhibit 10.1 of the Company s Form 8-K (File No. 001-12719) filed on December 10, 2007).
10.22	Capped Call Option Confirmation among Goodrich Petroleum Corporation and JP Morgan Chase Bank, National Association, dated December 4, 2007 (Incorporated by reference to Exhibit 10.2 of the Company s Form 8-K (File No. 001-12719) filed on December 10, 2007).
12.1*	Ratio of Earnings to Fixed Charges.
12.2*	Ratio of Earnings to Fixed Charges and Preference Securities Dividends.
16.1	Letter from KPMG LLP (Incorporated by reference to Exhibit 16.1 of the Company s 8-K (File No. 001-12719) filed on March 20, 2008).
21	Subsidiaries 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 KPMG LLP Independent Registered Public Accounting Firm.
23.3*	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.

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

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GLOSSARY OF CERTAIN OIL AND GAS TERMS

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

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

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

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

Dry hole is 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.

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 it s 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 intere