GOODRICH PETROLEUM CORP
Form 10-K
February 26, 2010

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2009

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

[Table of Contents](#)

[Index to Financial Statements](#)

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*.

Table of Contents

Index to Financial Statements

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.

12

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

[Table of Contents](#)

[Index to Financial Statements](#)

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 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

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

	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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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

34

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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:

	Year Ended December 31,			Year Ended December 31,		
Cash flow statement information:	**2009**	**2008**	**Variance**	**2008**	**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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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 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.

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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.*

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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).

Index to Financial Statements

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).

Table of Contents

Index to Financial Statements

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.

Table of Contents

Index to Financial Statements

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 interest transferred by the assignor is a farm-out.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The SEC provides a complete definition of field in Rule 4-10(a)(15).

PV-10 is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying the 12-month average price for the year and holding that price constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions).

Table of Contents

Index to Financial Statements

Productive well is an exploratory, development or extension well that is not a dry well.

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

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

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

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

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

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

Table of Contents

Index to Financial Statements

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

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

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

Table of Contents

Index to Financial Statements

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 26, 2010.

GOODRICH PETROLEUM CORPORATION

By: /s/ WALTER G. GOODRICH
Walter G. Goodrich

Chief Executive Officer

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant in the capacities indicated on February 26, 2010.

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

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

Table of Contents

Index to Financial Statements

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

Index to Financial Statements

MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROLS

OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and board of directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in Internal Control Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2009. The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on page F-3.

Management of Goodrich Petroleum Corporation

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited Goodrich Petroleum Corporation and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Goodrich Petroleum Corporation and subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Goodrich Petroleum Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2009 consolidated financial statements of Goodrich Petroleum Corporation and subsidiaries and our report dated February 26, 2010, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 26, 2010

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, stockholders equity, and comprehensive income (loss) for each of the two years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Goodrich Petroleum Corporation and subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2009, the Company changed its method of accounting for convertible debt instruments and applied the change retrospectively to all periods presented. Also, as discussed in Note 1 to the consolidated financial statements, as of December 31, 2009, the Company has changed its reserve estimates and related disclosures as as result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 26, 2010

Table of Contents

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Goodrich Petroleum Corporation:

We have audited the accompanying consolidated statements of operations, cash flows, stockholders equity, and comprehensive income (loss) of Goodrich Petroleum Corporation and subsidiaries for the year ended December 31, 2007. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and the cash flows of Goodrich Petroleum Corporation and subsidiaries for the year ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 17 to the consolidated financial statements, the consolidated financial statements have been adjusted for the retrospective application of an accounting policy related to convertible debt instruments which became effective January 1, 2009.

/s/ KPMG LLP

Houston, Texas

March 13, 2008, except for Note 17, as to which the date is

September 16, 2009

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(In Thousands)

	December 31, 2009	December 31, 2008 (as adjusted)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 125,116	$ 147,548
Accounts receivable, trade and other, net of allowance	7,944	7,019
Income taxes receivable	15,438	
Accrued oil and gas revenue	17,206	15,595
Fair value of oil and gas derivatives	5,403	55,276
Assets held for sale	13	13
Prepaid expenses and other	2,258	2,778
Total current assets	173,378	228,229
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,339,462	1,107,400
Furniture, fixtures and equipment	3,985	3,171
	1,343,447	1,110,571
Less: Accumulated depletion, depreciation and amortization	(669,463)	(304,236)
Net property and equipment	673,984	806,335
Deferred tax asset	4,700	
Deferred financing cost	8,212	3,723
TOTAL ASSETS	$ 860,274	$ 1,038,287
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 35,079	$ 41,462
Accrued liabilities	25,308	52,928
Accrued abandonment costs	4,574	2,554
Deferred tax liability current	4,700	18,931
Fair value of interest rate derivatives	1,087	1,187
Income taxes payable		1,383
Total current liabilities	70,748	118,445
LONG-TERM DEBT	330,147	226,723
Accrued abandonment costs	13,716	11,250
Deferred tax liability		15,904
Fair value of oil and gas derivatives	278	
Fair value of interest rate derivatives		617

Total liabilities	414,889	372,939
Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000	2,250	2,250
Common stock: $0.20 par value, 100,000,000 shares authorized, issued and outstanding 37,452,023 and 37,562,659 shares, respectively	7,166	7,188
Treasury stock (19,915 and 9,793 shares, respectively)	(411)	(293)
Additional paid in capital	637,335	600,125
Retained earnings (accumulated deficit)	(200,955)	56,078
Total stockholders equity	445,385	665,348
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 860,274	$ 1,038,287

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In Thousands, Except Per Share Amounts)

	Year Ended December 31, 2009	2008 (as adjusted)	2007 (as adjusted)
REVENUES:			
Oil and gas revenues	$ 110,784	$ 215,369	$ 110,691
Other	(358)	682	614
	110,426	216,051	111,305
OPERATING EXPENSES:			
Lease operating expense	30,188	31,950	22,465
Production and other taxes	4,317	7,542	2,272
Transportation	9,459	8,645	5,964
Depreciation, depletion and amortization	160,361	107,123	79,766
Exploration	9,292	8,404	7,346
Impairment of oil and gas properties	208,905	28,582	7,696
General and administrative	27,923	24,254	20,888
Gain on sale of assets	(297)	(145,876)	(42)
Other			109
	450,148	70,624	146,464
Operating income (loss)	(339,722)	145,427	(35,159)
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)
	21,400	31,321	(24,317)
Income (loss) from continuing operations before income taxes	(318,322)	176,748	(59,476)
Income tax benefit (expense)	67,311	(54,472)	9,294
Income (loss) from continuing operations	(251,011)	122,276	(50,182)
DISCONTINUED OPERATIONS			
Gain on sale of assets, net of tax (See Note 9)		29	9,662
Income (loss) on discontinued operations, net of tax	25	(531)	1,807
	25	(502)	11,469
Net income (loss)	(250,986)	121,774	(38,713)
Preferred stock dividends	6,047	6,047	6,047

Net income (loss) applicable to common stock	$ (257,033)	$ 115,727	$ (44,760)
PER COMMON SHARE			
Income (loss) from continuing operations basic	$ (7.00)	$ 3.61	$ (1.96)
Income (loss) from continuing operations diluted	$ (7.00)	$ 3.24	$ (1.96)
Income (loss) on discontinued operations, net of tax basic	$	$ (0.01)	$ 0.45
Income (loss) on discontinued operations, net of tax diluted	$	$ (0.01)	$ 0.45
Net income (loss) applicable to common stock basic	$ (7.17)	$ 3.42	$ (1.75)
Net income (loss) applicable to common stock diluted	$ (7.17)	$ 3.23	$ (1.75)
Weighted average common shares outstanding basic	35,866	33,806	25,578
Weighted average common shares outstanding diluted	35,866	40,397	25,578

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 2009	2008 (as adjusted)	2007 (as adjusted)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (250,986)	$ 121,774	$ (38,713)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	160,361	107,123	79,766
Unrealized (gain) loss on derivatives not designated for hedge accounting	49,434	(53,995)	16,079
Deferred income taxes	(51,845)	34,835	(3,303)
Exploration costs	219	312	939
Amortization of leasehold costs	4,927	5,838	6,211
Impairment of oil and gas properties	208,905	29,751	9,223
Share based compensation (non-cash)	6,751	5,493	5,282
Gain on sale of assets	(297)	(145,876)	(14,792)
Amortization of finance cost and debt discount	12,221	8,465	7,293
Other non-cash items	282	53	85
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	(925)	1,467	1,105
Income taxes receivable	(15,438)		
Deferred revenue		(12,500)	12,500
Accrued oil and gas revenue	(1,611)	(3,395)	(1,511)
Accounts payable	(6,338)	4,495	5,022
Income taxes payable	(1,320)	1,383	
Accrued liabilities	976	3,184	409
Prepaid expenses and other	254	(1,368)	330
Net cash provided by operating activities	115,570	107,039	85,925
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(265,825)	(362,847)	(291,486)
Proceeds from sale of assets	238	175,061	72,293
Net cash used in investing activities	(265,587)	(187,786)	(219,193)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from convertible note offering	218,500		
Principal payments of bank borrowings	(80,000)	(155,500)	(173,000)
Proceeds from bank borrowings	5,000	190,000	187,000
Exercise of stock options and warrants	26	2,819	203
Deferred financing costs	(8,755)	(1,498)	(439)
Preferred stock dividends	(6,047)	(6,047)	(6,047)
Net proceeds from common stock offering		191,340	123,815
Excess tax benefit from stock based compensation		3,222	
Other	(1,139)	(489)	

Net cash provided by financing activities	127,585	223,847	131,532
Increase (decrease) in cash and cash equivalents	(22,432)	143,100	(1,736)
Cash and cash equivalents, beginning of period	147,548	4,448	6,184
Cash and cash equivalents, end of period	$ 125,116	$ 147,548	$ 4,448
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$ 12,446	$ 12,981	$ 10,178
Cash paid during the year for taxes	$ 1,352	$ 14,778	$

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In Thousands)

	2009		2008		2007	
	Shares	Amount	Shares	Amount (as adjusted)	Shares	Amount (as adjusted)
Series B Preferred Stock						
Balance, beginning of year	2,250	$ 2,250	2,250	$ 2,250	2,250	$ 2,250
Issuance of preferred stock						
Balance, end of year	2,250	$ 2,250	2,250	$ 2,250	2,250	$ 2,250
Common Stock						
Balance, beginning of year	37,563	$ 7,188	34,821	$ 6,340	28,218	$ 5,049
Issuance of and amortization of restricted stock	129	26	53	11	108	(8)
Exercise of stock options	10	2	141	28	57	12
Director stock grants	16	3	16	3	7	1
Shares pursuant to share lending agreement			(1,498)			
Offering of common stock			4,030	806	6,431	1,286
Capped call options redemptions	(266)	(53)				
Balance, end of year	37,452	$ 7,166	37,563	$ 7,188	34,821	$ 6,340
Treasury Stock						
Balance, beginning of year	10	$ (293)	16	$ (422)		$
Purchases	44	(1,132)	16	(485)	40	(1,231)
Retirements	(34)	1,014	(22)	614	(24)	809
Balance, end of year	20	$ (411)	10	$ (293)	16	$ (422)
Additional Paid in Capital						
Balance, beginning of year		$ 600,125		$ 364,262		$ 236,877
Equity portion of Senior Convertible Notes and finance cost (net of tax)		31,165				(47)
Issuance of and amortization of restricted stock		4,276		2,686		1,745
Share based compensation		1,428		2,180		2,727
Excess tax benefit from stock based compensation		(163)		3,222		
Exercise of stock options		24		2,791		192
Director stock grants		426		579		239
Capped call options redemptions		54				
Offering of common stock				224,405		122,529
Balance, end of year		$ 637,335		$ 600,125		$ 364,262
Retained Earnings (Accumulated Deficit)						
Balance, beginning of year		56,078		(59,649)		(14,889)
Net income (loss)		(250,986)		121,774		(38,713)

Preferred stock dividend	(6,047)	(6,047)	(6,047)
Balance, end of year	$ (200,955)	$ 56,078	$ (59,649)
Accumulated Other Comprehensive Loss			
Balance, beginning of year	$	$	$ (1,261)
Other comprehensive income			1,261
Balance, end of year	$	$	$
Total Stockholders Equity at December 31	$ 445,385	$ 665,348	$ 312,781

See accompanying notes to consolidated financial statements.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In Thousands)

	Year Ended December 31,		
	2009	2008 (as adjusted)	2007 (as adjusted)
Net income (loss)	$ (250,986)	$ 121,774	$ (38,713)
Other comprehensive income (loss):			
Reclassification adjustment (1)			1,261
Other comprehensive income (loss)			1,261
Comprehensive income (loss)	$ (250,986)	$ 121,774	$ (37,452)
(1) Net of income tax expense of:	$	$	$ 679

See accompanying notes to consolidated financial statements.

F-10

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Accounting Policies

Goodrich Petroleum Corporation is in the primary business of exploration and production of crude oil and natural gas. We and our subsidiaries have interests in such operations, primarily in Texas and Louisiana.

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

Use of Estimates Our Management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with US GAAP.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase. As of December 31, 2009, we held short term investments in money market funds with three institutions meeting our short term investment policy criteria. As of December 31, 2009, short term investments totaled $117.5 million and carried maturities of fourteen days or less and are considered cash equivalents. We continue to monitor these institutions in light of the current financial market crisis and in accordance with our policy.

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

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of December 31, 2009 and 2008, our allowance for doubtful accounts was immaterial.

Assets Held for Sale We measure long-lived assets classified as assets held for sale at fair value less cost to sell and to cease depreciation, using level 3 unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices. 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. Assets held for sale as of December 31, 2009 represent our remaining assets in South Louisiana, the Plum Bob field.

Property and Equipment We follow the successful efforts method of accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases.

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

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

Impairment Proved oil and gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future net cash flows are calculated based on estimated future oil and gas sales revenues less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property s carrying amount over its estimated fair value based on estimated discounted future cash flows. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We perform this comparison using our estimates of future commodity prices and proved and probable reserves. For the years ended December 31, 2009, 2008 and 2007, we recorded impairments on continuing operations of $208.9 million, $28.6 million and $7.7 million, respectively. See Note 14.

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

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

Asset Retirement Obligations We follow the accounting standard related to accounting for asset retirement obligations. These obligations relate to the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in depreciation, depletion and amortization on our consolidated statement of operations.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. We record an asset or liability for natural gas balancing when we have purchased or sold more than our working interest share of natural gas production, respectively. At December 31, 2009, the net liability for gas balancing was $0.1 million. At December 31, 2008 and 2007, the net assets for gas balancing were $0.1 million and $1.2 million, respectively. Differences between actual production and net working interest volumes are routinely adjusted.

Derivative Instruments We use derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. We do not designate our derivative contracts as hedges accordingly, changes in fair value are reflected in earnings.

Income Taxes We account for income taxes, as required, under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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

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

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

Concentration of Credit Risk Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from the top three purchasers accounted for 32%, 19% and 10% of oil and gas revenues for

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the year ended December 31, 2009. Revenues from the top three purchasers accounted for 33%, 20% and 9% of oil and gas revenues for the year ended December 31, 2008. Revenues from the top three purchasers accounted for 31%, 23% and 10% of oil and gas revenues for the year ended December 31, 2007.

Share-Based Compensation We account for our share-based transactions using fair value and recognized compensation expense over the requisite service period. The fair value of each option award is estimated using a Black-Scholes option valuation model with various assumptions based on our estimates. Our assumptions include expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore, the dividend yield is zero. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

New Accounting Pronouncements

On January 1, 2009, we adopted an update to an accounting standard related to convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). The update required that such instruments should separately account for the liability and equity components in a manner that will reflect the issuer s nonconvertible debt borrowing rate. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The standard requires retrospective application to all periods presented in the financial statements with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented. Both our 3.25% Convertible Senior Notes due 2026 and our recently issued 5% Convertible Senior Notes due 2029 (See Note 4) are affected by this accounting standard. The retrospective adjustments related to the 3.25% Convertible Senior Notes due 2026 are reflected in our consolidated financial statements of prior periods 2008 and 2007. See Note 17.

On January 1, 2009, we adopted an update to an existing accounting standard related to disclosures about derivative instruments and hedging activities. The updated standard requires enhanced disclosures about why an entity uses derivative instruments and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The standard requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The adoption of this standard had no impact on our results of operations, cash flows or financial positions. See Note 8.

In the second quarter of 2009, we adopted the provisions of a new accounting standard relating to subsequent events, which establishes general standards of accounting for and disclosures of events that occur after the balance sheet date but before the financial statements are issued or are available to be issued. It requires the disclosure of the date through which an entity has evaluated subsequent events. Adoption of the standard had no impact on our consolidated financial statements.

In the second quarter of 2009, we adopted an update to accounting standards for disclosures about the fair value of financial instruments, which requires publicly-traded companies to provide disclosures on the fair value of financial instruments in interim financial statements. See Note 13.

In October 2009, FASB issued guidance on accounting for own-share lending arrangements in contemplation of convertible debt issuance. The standard requires that such share-lending arrangement be

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

measured at fair value at the date of issuance and recognized as an issuance cost with an offset to paid-in-capital and the loaned shares be excluded in the computation of basic and diluted earnings per share. The issuance cost is required to be amortized as interest expense over the life of the financing arrangement. The standard also requires additional disclosures including a description and the terms of the arrangement and the reason for entering into the arrangement. Retrospective application is required for all arrangements outstanding as of the beginning of the fiscal years beginning on or after December 15, 2009. As described in Note 4, we entered into a share lending arrangement in connection with the December 2006 issuance of our 3.25% Convertible Senior Notes due 2026. The impact of the provision on our financial statements, as it relates to the shares outstanding under the share lending agreement that we entered into in connection with the December 2006 issuance of our 3.25% Convertible Senior Notes due 2026, was evaluated and considered immaterial. We will adopt the standard on its effective date as of the beginning of the fiscal year beginning January 1, 2010.

In December 2008, the SEC issued a final rule adopting revisions to its oil and gas reporting disclosures. The revisions are intended to provide investors with more meaningful and comprehensive information related to the determination and disclosure of oil and gas reserves information. In January 2010, the FASB issued an update to accounting standards for oil and gas reserve estimations and disclosures. The provisions of both SEC final rule and FASB accounting update are effective for fiscal years ending on or after December 31, 2009. We adopted both SEC final rule and FASB accounting update on their effective date of December 31, 2009. There was no material impact on our consolidated financial statements as a result of the adoption.

In January 2010, the FASB issued an update to accounting standards for improving fair value measurement and disclosures. The update requires more robust disclosures about valuation techniques and inputs to fair value measurements and is effective for fiscal years beginning after December 31, 2009. We do not expect any material impact of this update on our financial statements.

NOTE 2 Share-Based Compensation Plans

Overview

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan replaces our previously adopted Goodrich Petroleum Corporation 1995 Stock Option Plan and 1997 Non-Employee Directors Stock Option Plan. No further awards will be granted under the previously adopted plans, however, those plans shall continue to apply to and govern awards made thereunder. The 2006 Plan provides for grants to employees and non-employee directors. Under the 2006 Plan, a maximum of 2.0 million new shares are reserved for issuance as awards of share options to officers, employees and non-employee directors. As of December 31, 2009, a total of 833,085 shares were available for future grants under the 2006 Plan.

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

The 2006 Plan provides that the Compensation Committee shall have the authority to determine the Participants to whom stock options, restricted stock, performance awards, phantom shares and Stock Appreciation Rights may be granted.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Total share-based compensation of $7.4 million, $5.9 million and $5.5 million for the years ended December 31, 2009, 2008 and 2007, respectively, has been recognized as a component of general and administrative expenses in the Consolidated Statement of Operations. The total income tax benefit associated with our share-based compensation recognized in our Consolidated Statement of Operations was $3.2 million for the year ended December 31, 2008.

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

	Year Ended December 31,		
	2009	2008	2007
Pretax stock option expense	$ 1,428	$ 2,181	$ 2,727
Pretax restricted stock expense	5,323	3,312	2,555
Pretax director stock expense	608	440	252
Total pretax share-based compensation:	$ 7,359	$ 5,933	$ 5,534

Stock Options

The 2006 Plan provides that the option price of shares issued be equal to the market price on the date of grant. With the exception of option grants to non-employee directors which vest immediately, options vest ratably on the anniversary of the date of grant over a period of time, typically three years. All options expire ten years after the date of grant.

Option activity under our stock option plans as of December 31, 2009, and changes during the year ended December 31, 2009 were as follows:

	Shares	Weighted Average Exercise Price	Remaining Contractual Term	Aggregate Intrinsic Value

			(years)	**(thousands)**
Outstanding at January 1, 2009	970,133	$ 21.20		
Granted				
Exercised	(10,000)	2.63		$ 183
Forfeited	(12,500)	21.59		
Outstanding at December 31, 2009	947,633	$ 21.39	5.51	$ 2,804
Exercisable at December 31, 2009	726,133	$ 21.15	5.55	$ 2,322

The aggregate intrinsic value in the preceding table represents the total pre-tax intrinsic value (the difference between our closing stock price on the last trading day of the fourth quarter of 2009 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2009. The amount of aggregate intrinsic value will

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

change based on the fair market value of our stock. The total intrinsic value of options exercised during the years ended December 31, 2009, 2008, and 2007 was $0.2 million, $6.2 million and $1.8 million, respectively. During 2009, 2008 and 2007, $1.4 million, $2.2 million and $2.7 million, respectively, were charged to General and Administrative (G&A) expense related to stock options.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding at December 31, 2009**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**	**Number Exercisable at December 31, 2009**	**Weighted Average Exercise Price**
$2.63 to $5.85	14,000	2.11	$ 4.93	14,000	$ 4.93
$16.46 and $19.78	307,300	5.11	18.08	307,300	18.08
$21.59 to $27.81	626,333	5.78	23.38	404,833	24.05
	947,633	5.51	$ 21.39	726,133	$ 21.15

During 2008 we granted 162,000 stock options under the plan, valued at $1.7 million, at the time of issuance. No options were granted in 2009 and 2007. The estimated fair value of the options granted during 2008 and prior years was calculated using a Black-Scholes Merton option pricing model (Black Scholes).

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

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

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

As of December 31, 2009, $2.0 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted average period of approximately 3.8 years.

Restricted Stock

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

During 2009, 2008 and 2007, we granted 343,749, 437,048 and 13,000 shares of our common stock, under the plan, valued at $7.8 million, $11.4 million and $0.4 million, respectively, at the time of issuance. During 2009, 2008 and 2007, $5.3 million, $3.3 million and $2.6 million, respectively, were charged to G&A expense

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

related to the restricted share awards. The fair value of restricted stock vested during 2009, 2008 and 2007 were $4.9 million, $2.1 million and $4.5 million, respectively.

Restricted stock activity under our plan for the year ended December 31, 2009, and changes during the year then ended were as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
Unvested at January 1, 2009	471,086	$ 27.13	$ 12,778,666
Vested	(173,302)	28.42	(4,924,668)
Granted	343,749	22.33	7,674,552
Forfeited	(17,947)	28.12	(504,696)
Unvested at December 31, 2009	623,586	$ 24.09	$ 15,023,854

As of December 31, 2009, $13.3 million of total unrecognized compensation cost related to restricted stock is expected to be recognized over a weighted average period of approximately 2.3 years.

NOTE 3 Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2009 and 2008 is as follows (in thousands):

	December 31, 2009	December 31, 2008
Beginning balance	$ 13,804	$ 6,180
Liabilities incurred	352	2,305
Revisions in estimated liabilities	3,299	5,063
Liabilities settled		
Accretion expense	891	331
Dispositions	(56)	(75)
Ending balance	$ 18,290	$ 13,804

Current liability	$ 4,574	$ 2,554
Long term liability	$ 13,716	$ 11,250

During 2009, we determined that the expected productive lives of many of our wells had decreased relative to the 2008 estimate, while the plug and abandon costs remained relatively flat with only slight increases. As a result, we revised our previously estimated asset retirement obligation by a discounted $3.3 million. The ending balance at December 31, 2009 and 2008 includes $1.4 million for Assets Held for Sale. See Note 9.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 4 Long-Term Debt

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

	December 31, 2009	2008
Senior Credit Facility	$	$
Second Lien Term Loan		75,000
3.25% Convertible Senior Notes due 2026	175,000	175,000
Debt discount on 3.25% convertible senior notes	(15,915)	(23,277)
5.0% Convertible Senior Notes due 2029	218,500	
Debt discount of 5.0% Convertible Senior Notes	(47,438)	
Total long-term debt	$ 330,147	$ 226,723

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 LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on April 1 and October 1 beginning on October 1, 2009. In connection with the offering of the $218.5 million 5% convertible senior notes due 2029, we entered into an amendment of our Senior Credit Facility to permit the issuance of the notes and required payments made on the notes thereafter and to exclude up to $175 million of our 3.25% convertible senior notes due 2026 or our 5% convertible senior notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. We currently have no amounts outstanding under the credit facility with a borrowing base of $175 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

- Total Debt no greater than 3.0 times EBITDAX for the trailing four quarters (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Up to $175.0 million of our convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

NOTE 5 Income (Loss) Per Common Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted income (loss) per common share for the years ended December 31, 2009, 2008 and 2007. The following table sets forth information related to the computations of basic and diluted income (loss) per share.

	Year Ended December 31,		
	2009	2008	2007
	(Amounts in thousands, except per share data)		
Basic income (loss) per share:			
Income (loss) applicable to common stock	$ (257,033)	$ 115,727	$ (44,760)
Weighted-average shares of common stock outstanding (1)	35,866	33,806	25,578
Basic income (loss) per share	$ (7.17)	$ 3.42	$ (1.75)
Diluted income (loss) per share:			
Income (loss) applicable to common stock	$ (257,033)	$ 115,727	$ (44,760)
Dividends on convertible preferred stock (2)		6,047	
Interest and amortization of loan cost on convertible senior notes, net of tax (3)		8,651	
Diluted income (loss)	$ (257,033)	$ 130,425	$ (44,760)

Weighted-average shares of common stock outstanding (1)		35,866		33,806		25,578
Assumed conversion of convertible preferred stock (2)				3,588		
Assumed conversion of convertible senior notes (3)				2,654		
Stock options and restricted stock (4)				349		
Weighted-average diluted shares outstanding		35,866		40,397		25,578
Diluted income (loss) per share	$	(7.17)	$	3.23	$	(1.75)

(1) This amount does not include 1,624,300 shares in 2009 and 2008, respectively, and 3,122,263 shares in 2007 of common stock outstanding under the Share Lending Agreement. See Note 7.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Common shares issuable upon assumed conversion of our convertible preferred stock amounting to 3,587,850 shares and the accrued dividends on the convertible preferred stock were not included in the computation of diluted loss per share for the periods presented in 2009 and 2007, as they would have been anti-dilutive.

(3) Common shares issuable upon assumed conversion of our convertible senior notes amounting to 8,958,394 shares in 2009 and 2,653,927 shares in 2007 and the accrued interest on the convertible senior notes were not included in the computation of diluted loss per share for the periods presented in 2009 and 2007, respectively, as they would have been anti-dilutive.

(4) Common shares on assumed conversion of restricted stock and stock options in the amounts of 125,131 shares and 210,180 shares for the years 2009 and 2007, respectively, were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.

NOTE 6 Income Taxes

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Current:			
Federal	$ 5,382	$ (5,331)	$ (97)
State	10,070	(10,813)	
	15,452	(16,144)	(97)
Deferred:			
Federal	48,121	(37,192)	3,303
State	3,725	(866)	
	51,846	(38,058)	3,303
Total	$ 67,298	$ (54,202)	$ 3,206

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Income tax (expense) benefit from continuing operations			
Tax at U.S. statutory income tax	$ 111,412	$ (61,861)	$ 20,833

Valuation allowance	(54,256)	15,268	(11,480)
State income taxes-net of federal benefit	10,271	(7,895)	
Nondeductible expenses and other	(116)	16	(59)
	67,311	(54,472)	9,294
Income tax (expense) benefit from discontinued operations			
Tax at U.S. statutory income tax	(13)	270	(6,088)
	(13)	270	(6,088)
Total tax (expense) benefit	$ 67,298	$ (54,202)	$ 3,206

F-22

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2009	December 31, 2008
Current deferred tax assets:		
Accrued liabilities	$ 980	$
Less valuation allowance	(650)	
Total current deferred tax assets	330	
Current deferred tax liabilities:		
Derivative financial instruments	(1,511)	(18,931)
Accrued liabilities	(3,519)	
Total current deferred tax liabilities	(5,030)	(18,931)
Net current deferred tax liability	$ (4,700)	$ (18,931)
Noncurrent deferred tax assets:		
Operating loss carryforwards	$ 47,902	$ 2,627
Statutory depletion carryforward	7,034	7,034
AMT tax credit carryforward	1,409	6,854
Derivative financial instruments	97	216
Compensation	3,042	2,403
Contingent liabilities and other	1,145	1,235
Property and equipment	31,572	
Total gross noncurrent deferred tax assets	92,201	20,369
Less valuation allowance	(61,091)	(7,486)
Net noncurrent deferred tax assets	31,110	12,883
Noncurrent deferred tax liabilities:		
Property and equipment		(17,680)
Bond discount	(4,872)	(2,960)
Debt discount	(21,538)	(8,147)
Total non-current deferred tax liabilities	(26,410)	(28,787)
Net non-current deferred tax asset (liability)	$ 4,700	$ (15,904)

The valuation allowance for deferred tax assets increased by $54.3 million in 2009. In determining the carrying value of a deferred tax asset, accounting standards provides for the weighing of evidence in estimating whether and how much of a deferred tax asset may be recoverable. As we have incurred net operating losses in 2009 and prior years, relevant accounting guidance suggests that cumulative losses in recent years constitute significant negative evidence, and that future expectations about income are insufficient to overcome a history of such losses. Therefore, with the before mentioned adjustment of $54.3 million, we have reduced the carrying value of our net deferred tax asset to zero. The valuation allowance has no impact on our net operating loss (NOL) position for tax purposes, and if we generate taxable income in future periods, we will be able to use our NOLs to offset taxes due at that time. The Company will continue to assess the valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

As of December 31, 2009, we have net operating loss carryforwards of approximately $139.1 million for tax purposes which begin to expire in 2026. The Company also has a minimum tax credit carryforward not subject to

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expiration of $1.4 million which will not begin to be used until after the available NOLs have been used or expired and when regular tax exceeds the current year alternative minimum tax.

Our share based deferred compensation plans have generated $11.5 million of additional tax deductions through 2009. The Company realized $9.2 million ($6.0 million, net of tax) of these deductions in 2008 and the associated $3.2 million tax benefit was recorded as additional paid in capital. The remaining tax deductions are not currently recognized as a component of our deferred tax asset. They will be recognized when the net operating loss carryforward is utilized to offset future taxable income.

In July 2005, we received a Notice of Proposed Tax Due from the State of Louisiana asserting that we underpaid our Louisiana franchise taxes for the years 1998 through 2004 in the amount of $0.6 million. The Notice of Proposed Tax Due includes additional assessments of penalties and interest in the amount of $0.4 million for a total asserted liability of $1.0 million. In order to avoid future penalties and interest, the Company paid, under protest, $1.0 million to the State of Louisiana in April 2007 which payment was expensed in general and administrative expense in first quarter 2007. We plan to pursue the reimbursement of the full $1.0 million paid under protest. Should our efforts prevail, the taxes paid under protest would be refunded, at which time we would book a credit to general and administrative expense.

As of December 31, 2009, we have recorded an income tax receivable of $15.4 million of which $10.1 million is a refund due from the State of Louisiana for 2008 taxes and $5.3 million is a refund due on federal income taxes as a result of the 2009 tax loss.

The amount of unrecognized tax benefits did not materially change as of December 31, 2009. The amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or our financial position. We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1992.

Our continuing practice is to recognize estimated interest and penalties related to potential underpayment on any unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations before December 31, 2010.

NOTE 7 Stockholders Equity

Caddo Parish Acquisition for Common Stock

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

Equity Offering

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Share Lending Agreement

In connection with the offering of our 3.25% notes in December 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 such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from the common stock offerings and lending transactions under this agreement. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of the notes to shares of our common stock pursuant to the terms of the indenture governing the notes.

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

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

The 1,624,300 shares of common stock outstanding as of December 31, 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.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility, and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of BSC and J.P. Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. One third of the options 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 remaining one-third of the options subject to the capped call will expire in May and June 2010.

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The remaining one-third of the options subject to the capped call will expire in May and June 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.

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

NOTE 8 Derivative Activities

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

The total financial impact of our derivative activities on our consolidated Statement of Operations for the year ended December 31, 2009 was a $47.1 million gain which consisted of $96.5 million in realized gain offset by $49.4 million in unrealized loss.

Commodity Derivative Activity

We produce and sell oil and natural gas into a market where selling prices are historically volatile. For example, on January 7, 2009 the Henry Hub natural gas spot price reached a high of $6.10 per MMbtu, but the price was down to $1.84 per MMBtu by September 8, 2009 and back up to $5.82 per MMBtu by December 31, 2009. We enter into swap contracts, costless collars or other derivative agreements from time to time to manage this commodity price risk for a portion of our production. Our strategy, which is administered by the Hedging Committee of our Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our estimated total production for the period the derivatives are in effect. As of December 31, 2009, the commodity derivatives we used were in the form of:

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

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

As of December 31, 2009, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, JP Morgan or Bank of Montreal, were as follows:

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.

The fair value of the oil and gas commodity contracts in place at December 31, 2009, that are marked to market resulted in a current asset of $5.4 million and a long-term liability of $0.3 million. We measure the fair value of our commodity derivatives contracts by applying the income approach, and these contracts are classified within level two of the valuation hierarchy. See Note 13. For the year ended December 31, 2009, we recognized in earnings a $47.8 million gain from these commodity derivative instruments, which consisted of $98.0 million in realized gain offset by $50.2 million in unrealized loss.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swap

We have variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. These swaps are not designated as hedges. At December 31, 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 at December 31, 2009, resulted in a liability of $1.1 million which is reflected on the balance sheet as a current liability. We measure the fair value of our interest rate swaps by applying the income approach and these contracts are classified within level two of the valuation hierarchy. See Note 13. For the years ended December 31, 2009, we recognized losses of $0.7 million, consisting of $1.4 million of realized loss offset by $0.7 million of unrealized gain from interest rate swaps.

NOTE 9 Discontinued Operations

On March 20, 2007, we closed the sale of substantially all of our oil and gas properties in South Louisiana with the exception of the St. Gabriel, Bayou Bouillon and Plumb Bob fields. The results of operations for the properties that were sold and for the properties that are held for sale have been reflected as discontinued operations. The operations of these properties have been eliminated from our ongoing operating results and we have no continuing involvement after the sale of the property. The St. Gabriel and Bayou Bouillon fields were sold in 2008. The Plumb Bob field, which is being held for sale, has been fully reserved and has an accrued abandonment cost liability of $1.4 million as of December 31, 2009.

The following table summarizes the amounts included in Income (loss) from discontinued operations net of tax (in thousands):

For Years Ended December 31,

	2009	2008	2007
Revenues	$ 299	$ 900	$ 9,470
Income (loss) from discontinued operations	38	(817)	2,766
Income tax benefit (expense)	(13)	286	(959)
Income (loss) from discontinued operations, net of tax	25	(531)	1,807

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 10 Commitments and Contingencies

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).

			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.

Operating Leases We have commitments under an operating lease agreement for office space and office equipment leases. Total rent expense for the years ended December 31, 2009, 2008, and 2007, was approximately $1.1 million, $0.9 million and $0.8 million.

Drilling Contracts We have three drilling rigs under contract as of December 31, 2009 of which two are scheduled to expire in 2011 and one is scheduled to expire in 2012.

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

NOTE 11 Related Party Transactions

Patrick E. Malloy, III, Chairman of the Board of Directors of our company is a principle of Malloy Energy Company, LLC (MEC). In 2003 and 2004 MEC acquired an approximate 30% working interest in the Bethany Longstreet, Plumb Bob and St. Gabriel fields for which we were the operator. In accordance with industry standard joint operating agreements, we bill MEC for its share of capital and operating cost on a monthly basis. As of December 31, 2009 and 2008, the amounts billed and outstanding to MEC for its share of monthly capital and operating costs were $1.4 million and $0.6 million, respectively, and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by MEC to us in the month after billing and the affiliate is current on payment of its billings.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At the same time we sold a portion of our interests in the Haynesville Shale deep rights at Bethany Longstreet field, MEC consummated a similar transaction for its 30% working interest in the same deep rights with Chesapeake Energy Corporation, or Chesapeake. We and MEC also sold our interest in the St. Gabriel field in August 2008. See Note 12.

We also serve as the operator for a number of other oil and gas wells owned by affiliates of MEC in which we will earn an average working interest of 11% after payout. In accordance with industry standard joint operating agreements, we bill the affiliate for its share of the capital and operating costs of these wells on a monthly basis. As of December 31, 2009 and 2008, the amounts billed and outstanding to the affiliate for its share of monthly capital and operating costs were both less than $0.1 million at the end of each period and are included in trade and other accounts receivable at each year-end. Such amounts at each year-end were paid by the affiliate to us in the month after billing and the affiliate is current on payment of its billings.

NOTE 12 Acquisitions and Divestitures

Acquisitions

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

Subsequent to December 31, 2009, we acquired approximately 380 net acres in Bossier Parish lease interest in Louisiana for $1.9 million which we believe is prospective for the Haynesville Shale.

Divestitures

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

NOTE 13 Fair Value Measurements

On January 1, 2008, we adopted new fair value accounting and reporting standards related to our financial assets and liabilities which consist primarily of commodity and interest rate derivatives and long-term debt. These standards also expanded the disclosure requirements for financial instruments and other derivatives recorded at fair value, and also required that a company s own credit risk be considered in determining the fair value of those instruments. The adoption of these standards did not have a material effect on our financial statements. On January 1, 2009 we adopted new accounting and reporting standards for our non-financial assets and liabilities that are measured at fair value on a non-recurring basis, which primarily relate to our oil and gas properties, assets held for sale, and initial recognition of asset retirement obligations. During the year ended December 31, 2009, the only non-financial assets and liabilities that were recorded at fair value subsequent to their initial measurement related to certain oil and gas properties which were deemed to be impaired (See Note 14).

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

As of December 31, 2009 and 2008, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each level as of December 31, 2009 and 2008 (in thousands):

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

	2008 Fair Value Measurements Using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current Assets				
Commodity Derivatives	$	$ 55,276	$	$ 55,276
Current Liabilities				
Interest Swaps		(1,187)		(1,187)
Non-current Liabilities				
Interest Swaps		(617)		(617)
Total	$	$ 53,472	$	$ 53,472

The following table reflects the carrying value, as recorded in our Consolidated Balance Sheet, and fair value of our long-term debt financial instruments as of December 31, 2009 and 2008 (in thousands):

	2009		**2008**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Second lien term loan	$	$	$ 75,000	$ 75,000
3.25% Convertible Senior Notes	159,085	161,438	151,723	132,948
5.0% Convertible Senior Notes	171,062	226,694		
Total long-term debt	$ 330,147	$ 388,132	$ 226,723	$ 207,948

The fair value amounts of our debt are based on quoted market prices for the same or similar type issues, including consideration of our credit risk related to those instruments and other relevant information generated by market transactions and derived from the market.

NOTE 14 Impairment of oil and gas properties

Methods for Determining Fair Value

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2009, we had interests in oil and gas properties totaling $672.3 million, net of accumulated depletion, which we account for under the successful efforts method. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimated future net cash flows generated from our oil and gas properties by using forecasted oil and gas prices.

Impairment of Oil and Gas Properties

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 from the calculations used in our impairment test. 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.

Total impairment associated with our oil and gas properties for the years ended December 31, 2009, 2008 and 2007 was $208.9 million, $28.6 million and $9.2 million, respectively. Included in 2007 was an impairment on properties held for sale of $1.5 million.

NOTE 15 Oil and Gas Producing Activities (Unaudited)

Overview

All of our reserve information related to crude oil, condensate, and natural gas liquids and natural gas was compiled based on estimates prepared and reviewed by Goodrich Petroleum Corporation s engineers. The technical persons primarily responsible for overseeing the preparation of the reserves estimates meet the requirements regarding qualifications. The reserves estimation is part of our internal controls process subject to Management s annual review and approval. These reserves estimates are evaluated and audited by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers consulting firm, as of December 31, 2009, 2008 and 2007. A report of NSAI is filed in Exhibit 99.1. All of the subject reserves are located in the continental United States, primarily in Texas and Louisiana.

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In December 2008, the SEC issued a final rule adopting revisions to its oil and gas reporting disclosures. The revisions are intended to provide investors with more meaningful and comprehensive information related to the determination and disclosure of oil and gas reserves information. In January 2010, the FASB issued an update to accounting standards for oil and gas reserve estimations and disclosures. The provisions of both SEC final rule and FASB accounting update are effective for fiscal years ending on or after December 31, 2009. We adopted both SEC final rule and FASB accounting update on their effective date of December 31, 2009. The rule changes, including those related to pricing and technology, are included in our reserves estimates. See Note 1- New Accounting Pronouncements.

Application of the new rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of 12-month average pricing at December 31, 2009 as required by the new rules generally has resulted in reporting less proved reserves as of December 31, 2009 than under the previous rules. Other changes in the rules (allowing the use of reliable technologies to book proved undeveloped reserves and a limitation on proved undeveloped reserves to those expected to be drilled within five years of their original booking) had differing effects, and sometimes opposite impacts on the final tabulation of reserves. Because of the potential increased expense and time required to prepare an analysis of a multitude of such input changes, we have chosen not to attempt such a reconciliation at this time.

Prices we used are based on the twelve-month un-weighted arithmetic average of the first-day-of-the-month price for the period January through December 2009. For oil volumes, the average WTI spot price of $57.65 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $3.87 per MMBtu is adjusted by lease for energy content, transportation fees, and regional price differentials.

Capitalized Costs

The table below reflects our capitalized costs related to our oil-and gas producing activities at December 31, 2009, and 2008 (in thousands):

	2009	2008
Proved properties	$ 1,305,694	$ 1,077,009
Unproved properties	37,931	33,429
	1,343,625	1,110,438
Less accumulated depreciation, depletion and amortization	(671,352)	(305,448)
Net oil and gas properties	$ 672,273	$ 804,990

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs Incurred

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Property Acquisition			
Unproved	$ 15,264	$ 54,657	$ 10,745
Proved	579	7,751	
Exploration	35,378	44,765	20,429
Development (1)	193,130	315,030	269,664
	$ 244,351	$ 422,203	$ 300,838

(1) Includes asset retirement costs of $3.7 million in 2009, $7.4 million in 2008 and $2.7 million in 2007.

The following table sets forth our net proved oil and gas reserves at December 31, 2009, 2008 and 2007 and the changes in net proved oil and gas reserves during such years:

	Natural Gas (MMcf)			Oil (MBbls)		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Proved reserves at beginning of period	390,449	346,930	187,012	1,983	1,810	3,201
Revisions of previous estimates (1)	(264,928)	(62,616)	10,884	(1,441)	(137)	714
Extensions, discoveries and improved recovery (2)	318,699	126,350	179,959	487	470	712
Purchases of minerals in place		2,988			15	
Sales of minerals in place	(28)	(14)	(15,111)		(1)	(2,610)
Production	(28,891)	(23,189)	(15,814)	(152)	(174)	(207)
Proved reserves at end of period	415,301	390,449	346,930	877	1,983	1,810
Proved developed reserves:						
Beginning of period	150,174	108,077	76,679	387	282	1,862
End of period	162,935	150,174	108,077	431	387	282

	Natural Gas Equivalents (MMcfe)		
	2009	**2008**	**2007**
Proved reserves at beginning of period	402,349	357,792	206,217
Revisions of previous estimates (1)	(273,577)	(63,438)	15,169
Extensions, discoveries and improved recovery (2)	321,622	129,170	184,232
Purchases of minerals in place		3,078	
Sales of minerals in place	(28)	(20)	(30,770)
Production	(29,805)	(24,233)	(17,056)
Proved reserves at end of period	420,561	402,349	357,792
Proved developed reserves:			
Beginning of period	152,496	109,769	87,851
End of period	165,519	152,496	109,769

(1) Revisions of previous estimates were positive in 2007 in the aggregate due to a combination of increased prices from the end of 2006 to the end of 2007 and volume revisions resulting from updated production

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

performance in many of our fields. Alternatively, the revisions of previous estimates in 2008 and 2009 were negative due primarily to significant pricing decreases in 2008 and 2009 which caused a number of our vertical proved undeveloped locations in the East Texas North Louisiana (ETNL) area to become uneconomic at those lower price levels.

(2) Extensions and discoveries were positive on an overall basis in all three periods presented, primarily related to our continued drilling activity on existing and newly acquired properties in the ETNL.

Standardized Measure

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

	2009	2008	2007
Future revenues	$ 1,267,712	$ 2,052,735	$ 2,399,272
Future lease operating expenses and production taxes	(420,687)	(816,941)	(794,960)
Future development costs (1)	(422,042)	(675,787)	(709,355)
Future income tax expense	(3,384)	(6,907)	(103,186)
Future net cash flows	421,599	553,100	791,771
10% annual discount for estimated timing of cash flows	(274,375)	(385,657)	(507,654)
Standardized measure of discounted future net cash flows	$ 147,224	$ 167,443	$ 284,117
Index price used to calculate reserves (2)			
Natural gas (per Mcf)	$ 3.87	$ 5.71	$ 6.80
Oil (per Bbl)	$ 57.65	$ 41.00	$ 92.50

(1) Includes cumulative asset retirement obligations of $18.3 million, $13.8 million and $6.2 million in 2009, 2008 and 2007, respectively.

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

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

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in the Standardized Measure

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

	Year Ended December 31, 2009	2008	2007
Balance, beginning of year	$ 167,443	$ 284,117	$ 200,281
Net changes in prices and production costs related to future production	(309,832)	(68,643)	94,478
Sales and transfers of oil and gas produced, net of production costs	(66,438)	(167,516)	(85,216)
Net change due to revisions in quantity estimates	(181,646)	(81,292)	33,703
Net change due to extensions, discoveries and improved recovery	89,811	105,257	178,579
Net change due to purchases and sales of minerals in place	3	5,219	(99,628)
Changes in future development costs	473,897	3,426	(48,595)
Previously estimated development cost incurred in period	6,160	35,926	15,292
Net change in income taxes	1,461	26,165	(14,660)
Accretion of discount	16,987	31,269	21,419
Change in production rates (timing) and other	(50,622)	(6,485)	(11,536)
Net increase (decrease) in standardized measures	(20,219)	(116,674)	83,836
Balance, end of year	$ 147,224	$ 167,443	$ 284,117

NOTE 16 Summarized Quarterly Financial Data (Unaudited)

(In Thousands, Except Per Share Amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2009					
Revenues	$ 28,461	$ 26,263	$ 23,525	$ 32,177	$ 110,426
Operating loss	(27,546)	(53,947)	(37,740)	(220,489)	(339,722)
Net income (loss)	3,144	(34,982)	(29,519)	(189,629)	(250,986)
Net income (loss) applicable to common stock	1,632	(36,494)	(31,031)	(191,140)	(257,033)
Basic income (loss) per common share	0.05	(1.02)	(0.87)	(5.34)	(7.17)
Diluted income (loss) per common share	0.05	(1.02)	(0.87)	(5.34)	(7.17)
2008					

Revenues	$ 46,353	$ 65,173	$ 60,376	$ 44,149	$ 216,051
Operating income (loss)	3,603	16,055	158,003	(32,234)	145,427
Net income (loss)	(25,520)	(39,139)	186,302	131	121,774
Net income (loss) applicable to common stock	(27,032)	(40,650)	184,790	(1,381)	115,727
Basic income (loss) per common share	(0.85)	(1.27)	5.21	(0.04)	3.42
Diluted income (loss) per common share	(0.85)	(1.27)	4.47	(0.04)	3.23

NOTE 17 Retrospective Effect of Adoption of New Accounting Standard

On January 1, 2009, we adopted an update to an accounting standard related to convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). The update required that such instruments should separately account for the liability and equity components in a manner that will reflect the issuer s nonconvertible debt borrowing rate. The resulting debt discount would be amortized over the period the

Table of Contents

Index to Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

convertible debt is expected to be outstanding as additional non-cash interest expense. The standard requires retrospective application to all periods presented in the financial statements with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented. Our 3.25% Convertible Senior Notes due 2026 are affected by this accounting standard. The retrospective adjustments related to the 3.25% Convertible Senior Notes due 2026 are reflected in our consolidated financial statements of prior periods 2008 and 2007.

The following table summarizes the retrospective effect of the adoption of the standard related to convertible debt instruments that may be settled in cash upon conversion on the consolidated balance sheets as of December 31, 2008 and 2007, respectively:

	Previously Reported	Adjustment (in thousands)	Adjusted
December 31, 2008			
Deferred financing cost	$ 4,382	$ (659)	$ 3,723
Long-term debt	250,000	(23,277)	226,723
Deferred income tax liability	7,988	7,916	15,904
Additional paid in capital	576,961	23,164	600,125
Retained earnings	64,540	(8,462)	56,078
December 31, 2007			
Additional paid in capital	$ 341,098	$ 23,164	$ 364,262
Retained earnings	(65,651)	6,002	(59,649)

The following table summarizes the retrospective effect of the adoption of the standard related to convertible debt instruments that may be settled in cash upon conversion on the consolidated statements of operations for the years ended December 31, 2008 and 2007, respectively:

	Previously Reported	Adjustment (in thousands, except per share data)	Adjusted
Year ended December 31, 2008			
Interest Expense	$ 15,862	$ 6,548	$ 22,410
Income tax expense	46,556	7,916	54,472
Net income (loss) applicable to common stock	130,191	(14,464)	115,727
Net income (loss) applicable to common stock per share			
Basic	3.85	(0.43)	3.42
Diluted	3.48	(0.25)	3.23
Year ended December 31, 2007			
Interest Expense	$ 11,870	$ 6,008	$ 17,878
Income tax expense (benefit)	3,034	(12,328)	(9,294)
Net income (loss) applicable to common stock	(51,080)	6,320	(44,760)
Net income (loss) applicable to common stock per share			

Basic	(2.00)	0.25	(1.75)
Diluted	(2.00)	0.25	(1.75)

Table of Contents

Index to Financial Statements

EXHIBIT INDEX

	Exhibit
Ratio of Earnings to Fixed Charges	12.1
Ratio of Earnings to Fixed Charges and Preference Securities Dividends	12.2
Consent of Independent Registered Public Accounting Firm	23.1
Consent of Independent Registered Public Accounting Firm	23.2
Consent of Independent Petroleum Engineers and Geologists	23.3
Certification Pursuant to 15 U.S.C. Section 7241 as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification Pursuant to 15 U.S.C. Section 7241 as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification Pursuant to 18 U.S.C. Section 1350 as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1
Certification Pursuant to 18 U.S.C. Section 1350 as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.2
Report of Netherland, Sewell & Associates Inc. Independent Petroleum Engineers and Geologists	99.1