GOODRICH PETROLEUM CORP
Form 10-Q
November 04, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2011

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)

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

The number of shares outstanding of the Registrant s common stock as of October 31, 2011 was 36,126,574.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)

	September 30, 2011 (unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,441	$ 17,788
Restricted cash	29,286	4,232
Accounts receivable, trade and other, net of allowance	6,588	9,231
Income taxes receivable	729	4,335
Accrued oil and gas revenue	21,940	14,920
Fair value of oil and natural gas derivatives	44,823	24,467
Inventory	8,765	7,831
Prepaid expenses and other	1,904	3,045
Total current assets	117,476	85,849
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,494,813	1,217,891
Furniture, fixtures and equipment	5,568	4,962
	1,500,381	1,222,853
Less: Accumulated depletion, depreciation and amortization	(778,465)	(685,110)
Net property and equipment	721,916	537,743
Fair value of oil and natural gas derivatives	6,853	15,732
Deferred tax assets	18,494	19,695
Deferred financing cost	11,245	5,558
TOTAL ASSETS	$ 875,984	$ 664,577
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 61,055	$ 47,106
Accrued liabilities	38,421	47,105
Accrued abandonment costs	4,711	4,392
Deferred tax liabilities current	18,494	19,695
Current portion of debt	24,837	167,086
Total current liabilities	147,518	285,384
LONG-TERM DEBT	540,254	179,171
Accrued abandonment costs	11,797	11,683
Fair value of oil and natural gas derivatives	9,849	4,367

Total liabilities	709,418	480,605
Commitments and contingencies (See Note 9)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized: Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 shares	2,250	2,250
Common stock: $0.20 par value, 100,000,000 shares authorized; issued and outstanding 36,125,946 and 37,685,378 shares, respectively	7,225	7,212
Treasury stock (none and 12,377 shares, respectively)		(196)
Additional paid in capital	640,202	643,828
Retained earnings (accumulated deficit)	(483,111)	(469,122)
Total stockholders equity	166,566	183,972
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 875,984	$ 664,577

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, Except Per Share Amounts)

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010 (As adjusted)	2011	2010 (As adjusted)
REVENUES:				
Oil and gas revenues	$ 55,537	$ 37,443	$ 148,889	$ 111,920
Other	5	(19)	755	121
	55,542	37,424	149,644	112,041
OPERATING EXPENSES:				
Lease operating expense	5,447	6,280	15,565	19,841
Production and other taxes	1,599	664	4,194	2,017
Transportation	2,795	2,977	7,482	7,619
Depreciation, depletion and amortization	37,348	26,022	93,234	84,638
Exploration	1,638	2,033	6,379	7,639
Impairment	142	234,887	1,192	234,887
General and administrative	6,251	7,275	21,829	23,722
Gain on sale of assets			(236)	
Other	146	(4,232)	146	4,268
	55,366	275,906	149,785	384,631
Operating income (loss)	176	(238,482)	(141)	(272,590)
OTHER INCOME (EXPENSE):				
Interest expense	(13,022)	(9,154)	(36,815)	(27,469)
Interest income and other	21	11	43	117
Gain on derivatives not designated as hedges	26,453	22,494	27,397	57,543
Gain on extinguishment of debt	4		62	
	13,456	13,351	(9,313)	30,191
Income (loss) before income taxes	13,632	(225,131)	(9,454)	(242,399)
Income tax benefit (expense)				
Net income (loss)	13,632	(225,131)	(9,454)	(242,399)
Preferred stock dividends	1,511	1,511	4,535	4,535
Net income (loss) applicable to common stock	$ 12,121	$ (226,642)	$ (13,989)	$ (246,934)
PER COMMON SHARE				
Net income (loss) applicable to common stock basic	$ 0.34	$ (6.31)	$ (0.39)	$ (6.88)
Net income (loss) applicable to common stock diluted	$ 0.33	$ (6.31)	$ (0.39)	$ (6.88)
Weighted average common shares outstanding basic	36,125	35,936	36,104	35,904

Weighted average common shares outstanding diluted	36,297	35,936	36,104	35,904

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine months ended September 30,	
	2011	**2010 (As adjusted)**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (9,454)	$ (242,399)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	93,234	84,638
Unrealized gain on derivatives not designated as hedges	(5,995)	(42,994)
Exploration costs		1,225
Impairment of oil and gas properties	1,192	234,887
Amortization of leasehold costs	4,201	4,467
Share based compensation (non-cash)	4,526	5,496
Gain on sale of assets	(236)	
Gain on extinguishment of debt	(62)	
Amortization of finance cost and debt discount	11,677	14,242
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	1,361	6,249
Accrued oil and gas revenue	(7,020)	4,662
Inventory	(934)	(7,195)
Income taxes receivable/payable	3,606	10
Prepaid expenses and other	(296)	(49)
Restricted cash		(8,465)
Accounts payable	13,881	14,062
Accrued liabilities	256	8,126
Net cash provided by operating activities	109,937	76,962
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(288,067)	(184,081)
Proceeds from sale of assets	172	3
Net cash used in investing activities	(287,895)	(184,078)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments of bank borrowings	(30,000)	
Proceeds from bank borrowings	109,500	
Repurchase of convertible notes	(151,808)	
Cash restricted for repurchase of convertible notes	(25,054)	
Proceeds from high yield offering	275,000	
Exercise of stock options and warrants		10
Debt issuance costs	(9,104)	(318)
Preferred stock dividends	(4,535)	(4,535)
Other	(388)	(592)
Net cash (used in) provided by financing activities	163,611	(5,435)

DECREASE IN CASH AND CASH EQUIVALENTS	(14,347)	(112,551)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	17,788	125,116
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 3,441	$ 12,565

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Significant Accounting Policies

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

The consolidated financial statements of the Company included in this Quarterly Report on Form 10-Q have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) and accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (US GAAP) has been condensed or omitted. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Significant intercompany balances and transactions have been eliminated in consolidation.

The accompanying consolidated financial statements of the Company should be read in conjunction with the consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2010. The results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year.

Reclassifications Certain amounts for prior periods have been reclassified to conform to current year presentation. These reclassifications have no impact on net income or loss.

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.

Restricted Cash Restricted cash represents cash held in escrow of $29.3 million as of September 30, 2011 which includes $4.2 million for a suspensive appeal bond and $25.1 million for the redemption of the remaining outstanding 3.25% Convertible Senior Notes due 2026. See Notes 3 and 9.

Inventory Inventory consists of casing and tubulars that are expected to be used in our drilling operations and crude oil in storage tanks. Crude oil inventory is carried on the balance sheet at the lower of cost or market.

Derivative Instruments We use derivative instruments such as collars and swaps to hedge our exposure to fluctuations in the price of crude oil and natural gas. 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, and accordingly changes in fair value are reflected in earnings. See Note 7.

Impairment Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future net cash flows are calculated based on estimated future oil and gas sales revenues less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property s carrying amount over its estimated fair value based on estimated discounted future cash flows. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We perform this comparison using estimates of future commodity prices and our estimates of proved and probable reserves and recent market transactions. For the three and nine months ended September 30, 2011, we recorded impairments of $0.1 million and $1.2 million, respectively.

The carrying amount of our oil and natural gas properties was written down by $234.9 million as of September 30, 2010. The previously reported amount of $223.3 million was subsequently increased by $11.6 million in the fourth quarter of 2010 as a result of further analysis of our September 30, 2010 impairment calculation. As such, operating income, net income and our basic and diluted loss per common share for the three and nine months ended September 30, 2010 have been adjusted as well.

The effect of the adjustment on the basic and diluted loss per share in the three and nine months ended September 30, 2010 was a decrease of $0.33 and $0.32 per common share, respectively.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes We account for income taxes 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. See Note 5.

NOTE 2 Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the nine months ending September 30, 2011, is as follows (in thousands):

	September 30, 2011
Beginning balance	$ 16,075
Liabilities incurred	399
Liabilities settled or sold	(1,949)
Revisions in estimated liabilities	1,050
Accretion expense	933
Ending balance	16,508
Current liability	4,711
Long term liability	$ 11,797

NOTE 3 Debt

Debt consisted of the following balances as of the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Senior Credit Facility	$ 79,500	$
8.875% Senior Notes due 2019	275,000	
3.25% Convertible Senior Notes due 2026	25,043	175,000
Debt discount on 3.25% Convertible Senior Notes due 2026	(206)	(7,914)
5.0% Convertible Senior Notes due 2029	218,500	218,500
Debt discount on 5.0% Convertible Senior Notes due 2029	(32,746)	(39,329)
Total debt	$ 565,091	$ 346,257

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (the Senior Credit Facility) that replaced our previous facility. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The primary conditions for the effectiveness

of the Fourth Amendment were (i) the closing of the issuance and sale of our 8.875% Notes due 2019 (the 2019 Notes), and (ii) the placement of not less than $175 million of net proceeds from the sale of the 2019 Notes in an escrow account with the lenders to be used for the redemption or earlier repurchase of all our outstanding 3.25% Convertible Senior Notes due 2026 (the 2026 Notes), both of which occurred on March 2, 2011.

Total lender commitments under the Senior Credit Facility are $600 million subject to borrowing base limitations as of September 30, 2011 of $225 million. The Senior Credit Facility matures on July 1, 2014 (subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029 (the 2029 Notes). Revolving borrowings under the Senior Credit Facility are limited to, and subject to, periodic redeterminations of 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 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. As of September 30, 2011, we had $79.5 million outstanding under the Senior Credit Facility. Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used here, but not defined, have the meanings assigned to them in the Senior Credit Facility. In October 2011, we entered into a Sixth Amendment to the Senior Credit Facility which amended the EBITDAX annualized calculation and increased the borrowing base to $275 million. The primary financial covenants include:

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of EBITDAX of not less than 2.5/1.0 for the trailing four quarters or when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters. The interest for such period to apply solely to the cash portion of interest expense; and
- Total Debt no greater than 4.0 times EBITDAX for the trailing four quarters. Total Debt used in such ratio to be reduced by the amount of any restricted cash held in an escrow account established for the benefit of the lenders and dedicated to the redemption or prepayment of the 2026 Notes, the 2029 Notes or the 2019 Notes; provided that such ratios, when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters.

As defined in the credit agreement EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense, stock based compensation 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.

We were in compliance with all the financial covenants of the Senior Credit Facility as of September 30, 2011.

8.875% Senior Notes due 2019

On March 2, 2011, we sold $275 million of our 2019 Notes. The 2019 Notes mature on March 15, 2019, unless earlier redeemed or repurchased. The 2019 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2019 Notes accrue interest at a rate of 8.875% annually, and interest is paid semi-annually in arrears on March 15 and September 15. The 2019 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

Before March 15, 2014, we may on one or more occasions redeem up to 35% of the aggregate principal amount of the 2019 Notes at a redemption price of 108.875% of the principal amount of the 2019 Notes, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings. On or after March 15, 2015, we may redeem all or a portion of the 2019 Notes at redemption prices (expressed as percentages of principal amount) equal to (i) 104.438% for the twelve-month period beginning on March 15, 2015; (ii) 102.219% for the twelve-month period beginning on March 15, 2016 and (iii) 100.000% on or after March 15, 2017, in each case plus accrued and unpaid interest to the redemption date. In addition, prior to March 15, 2015, we may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2019 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem or retire such capital stock; (iii) sell assets, including the capital stock of our restricted subsidiaries; (iv) pay dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. These covenants are subject to a number of important exceptions and qualifications. At any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the indenture governing the 2019 Notes) has occurred and is continuing, many of these covenants will terminate.

Interest expense recognized relating to the contractual interest rate and amortization of financing cost for the three and nine months ended September 30, 2011 was $6.3 million and $14.6 million, respectively. The effective interest rate on the liability component of the 2019 Notes was 9.1% and 9.2% for the three and nine month periods ended September 30, 2011, respectively.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of our 2029 Notes. The 2029 Notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The 2029 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2029 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 2029 Notes on September 28, 2009.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Before October 1, 2014, we may not redeem the 2029 Notes. On or after October 1, 2014, we may redeem all or a portion of the 2029 Notes for cash, and the investors may require us to repurchase the 2029 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.

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

The 2029 Notes are convertible into shares of our common stock at a rate equal to 28.8534 shares per $1,000 principal amount of 2029 Notes (equal to an initial conversion price of approximately $34.66 per share of common stock).

We separately account for the liability and equity components of the 2029 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. As of September 30, 2011, the $218.5 million aggregate principal amount of the 2029 Notes was carried on the balance sheet at $185.8 million with a debt discount balance of $32.7 million. As of December 31, 2010, the $218.5 million aggregate principal amount of the 2029 Notes was carried on the balance sheet at $179.2 million with a debt discount of $39.3 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 debt discount and financing cost for the three and nine months ended September 30, 2011, was $5.2 million and $15.5 million, respectively. The effective interest rate on the liability component of the 2029 Notes was 11.1% and 11.4% for the three and nine month periods ended September 30, 2011, respectively. The 2029 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

3.25% Convertible Senior Notes Due 2026

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

During the nine months ended September 30, 2011, we repurchased $149.9 million of our 2026 Notes using a portion of the net proceeds from the issuance of our 2019 Notes. We paid premiums of 101.25%, 100.75% and 100.5% of face value in addition to accrued interest. We recorded each of the three and nine months ended September 30, 2011, a $0.1 million gain on the early extinguishment of debt related to the repurchase. Due to the repurchases, the debt discount was reduced to$0.2 million as of September 30, 2011 to be amortized over the next two months. Under the terms of our Senior Credit Facility, we have deposited in escrow $25.1 million to be used for the redemption of the remaining outstanding 2026 Notes.

Holders may present to us for redemption the remaining outstanding 2026 Notes on or before December 1, 2011. If the holders do not present the notes to us for redemption by December 1, 2011 they may not be redeemed until December 1, 2016. As of September 30, 2011, we have classified the 2026 Notes as a current liability. The balance not redeemed by December 1, 2011 will be reclassified as a long-term liability.

Interest expense relating to the contractual interest rate and amortization of debt discount and financing cost relating to the 2026 Notes for the three and nine months ended September 30, 2011 was $0.5 million and $3.9 million, respectively. The effective interest rate on the liability component of the 2026 Notes was 8.7% and 9.1% for the three and nine month periods ended September 30, 2011, respectively.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 4 Net Income (Loss) Per Common Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted income per common share for the three and nine months ended September 30, 2011, and 2010. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Amounts in thousands, except per share data)			
Basic income (loss) per share:				
Net income (loss) applicable to common stock	$ 12,121	$ (226,642)	$ (13,989)	$ (246,934)
Average shares of common stock outstanding (1)	36,125	35,936	36,104	35,904
Basic income (loss) per share	$ 0.34	$ (6.31)	$ (0.39)	$ (6.88)
Diluted income (loss) per share:				
Net income (loss) applicable to common stock	$ 12,121	$ (226,642)	$ (13,989)	$ (246,934)
Dividends on convertible preferred stock (2)				
Interest and amortization of loan cost on senior convertible notes, net of tax (3)				
	$ 12,121	$ (226,642)	$ (13,989)	$ (246,934)
Average shares of common stock outstanding (1)	36,125	35,936	36,104	35,904
Assumed conversion of convertible preferred stock (2)				
Assumed conversion of convertible senior notes (3)				
Stock options and restricted stock (4)	172			
Average diluted shares outstanding	36,297	35,936	36,104	35,904
Diluted income (loss) per share	$ 0.33	$ (6.31)	$ (0.39)	$ (6.88)
(1) Shares of common stock outstanding under the Share Lending Agreement were not included in the shares outstanding. See Note 6.		1,624,300		1,624,300
(2) Common shares issuable upon assumed conversion of convertible preferred stock were not presented as they would have been anti-dilutive.	3,587,850	3,587,850	3,587,850	3,587,850
(3) Common shares issuable upon assumed conversion of the 2026 Notes and the 2029 Notes were not presented as they would have been anti-dilutive.	6,689,783	8,958,394	7,234,357	8,958,394
(4) Common shares issuable on assumed conversion of restricted stock and employee stock option were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.		115,109	176,026	98,163

NOTE 5 Income Taxes

We recorded no income tax expense or benefit for the three and nine months ended September 30, 2011. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed, and, as a result, we continue to maintain a full valuation allowance for our net deferred assets as of September 30, 2011.

As of September 30, 2011, we had no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2010. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or prior to the expiration of statute of limitations on September 30, 2012.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6 Stockholders Equity

Restricted Stock

	Three months ended September 30, 2011	Nine months ended September 30, 2011
Restricted shares vested	5,483	75,196
Weighted average grant date value per share	$ 24.87	$ 22.14

Share Lending Agreement

In connection with the offering of our 2026 Notes in December 2006, 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. In March 2008, BSC returned 1,497,963 shares of the 3,122,263 originally borrowed shares. The 1,497,963 shares returned to us were recorded as treasury stock and retired. In May 2008, JP Morgan Chase & Co. completed its acquisition of and assumed all counterparty liabilities of BSC.

In conjunction with the partial repurchase of our 2026 Notes in March 2011, the Share Lending Agreement was terminated and JP Morgan Chase & Co. returned the remaining 1,624,300 shares. The shares returned to us were recorded as treasury shares and retired in March 2011. The shares were 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 had no impact on the earnings per share calculation.

NOTE 7 Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices and interest rates. We did not designate 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 Statements of Operations.

The following table summarizes the realized and unrealized gains and losses we recognized on our oil and natural gas derivatives for the three and nine month periods ended September 30, 2011 and 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Oil and Natural Gas Derivatives (in thousands)	**2011**	**2010**	**2011**	**2010**
Realized gain on oil and natural gas derivatives	$ 8,290	$ 6,329	$ 21,402	$ 15,658
Unrealized gain on oil and natural gas derivatives	18,163	16,165	5,995	41,907
Total gain on oil and natural gas derivatives	$ 26,453	$ 22,494	$ 27,397	$ 57,565

Commodity Derivative Activity

We enter into swap contracts, costless collars and other derivative agreements from time to time to manage the 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 September 30, 2011, 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;

(b) swaps, where we receive a fixed price and pay a floating price, based on NYMEX or specific transfer point quoted prices;

(c) swaptions, where we grant the counter party the right but not the obligation to enter into an underlying swap by a specific date.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the third quarter of 2011, we entered into the following new derivative contracts.

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 101.50	August 1, 2011	January 31, 2013
Oil swap (BBL)	1,000	$ 101.00	January 1, 2012	December 31, 2012
Oil swaption (BBL)	1,000	$ 101.00	January 1, 2013	December 31, 2013
Oil swaption (BBL)	1,000	$ 101.00	January 1, 2014	December 31, 2014
Natural gas swap (MMBtu)	20,000	$ 5.35	January 1, 2012	December 31, 2012
Natural gas swaption (MMBtu)	20,000	$ 5.35	January 1, 2013	December 31, 2013
Natural gas swaption (MMBtu)	20,000	$ 5.35	January 1, 2014	December 31, 2014

After September 30, 2011, we entered into the following new derivative contracts:

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 97.30	January 1, 2012	December 31, 2012
Oil swaption (BBL)	500	$ 97.30	January 1, 2013	December 31, 2013
Oil swaption (BBL)	500	$ 97.30	January 1, 2014	December 31, 2014

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.

As of September 30, 2011, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, Bank of Montreal, Royal Bank of Canada and JPMorgan Chase Bank, N.A., were as follows:

Contract Type	Daily Volume	Total Volume	Average Floor/Cap		Fair Value at September 30, 2011 (in thousands)
Natural gas collars (MMBtu)					$ 33,845
4Q 2011	40,000	3,680,000	$ 6.00	$7.09	
2012	40,000	14,640,000	$ 6.00	$7.09	
			Fixed Price		
Natural gas swaps (MMBtu)					7,673
2012	20,000	7,320,000	$ 5.35		
Natural gas swaptions (MMBtu)					(6,511)
2013	20,000	7,300,000	$ 5.35		
2014	20,000	7,300,000	$ 5.35		
Oil swaps (BBL)					14,250
4Q 2011	1,500	138,000	$ 100.00	$112.00	
2012	1,500	549,000	$ 101.00	$101.50	
2013	500	15,500	$ 101.50		
Oil swaptions (BBL)					(7,430)
2012	1,000	365,200	$ 100.00	$112.00	
2013	2,000	730,800	$ 100.00	$112.00	
2014	1,000	365,000	$ 101.00		

Total	$	41,827

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value of our natural gas derivative contracts in place at September 30, 2011, resulted in a current asset of $44.8 million, a non-current asset of $6.8 million and a non-current liability of $9.8 million. We measure the fair value of our commodity derivatives contracts by applying the income approach, and these contracts are classified within Level 2 of the valuation hierarchy. See Note 8.

NOTE 8 Fair Value

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, our 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 our various assumptions and future commodity prices. Included in this level are our oil and gas properties which are deemed impaired.

As of September 30, 2011, the carrying amounts of our cash and cash equivalents, restricted cash, trade receivables and payables represented fair value because of the short-term nature of these instruments.

We periodically assess our long-lived assets recorded in oil and gas properties on the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value, which is computed using Level 3 inputs such as discounted cash flow models or valuations, based on estimated future commodity prices and our various operational assumptions.

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value in our Consolidated Balance Sheet by applying the income approach and are classified in Level 2 as of September 30, 2011 (in thousands):

	September 30, 2011 Fair Value Measurements	December 30, 2010 Fair Value Measurements

Description	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Current Assets								
Commodity Derivatives	$	$ 44,823	$	$ 44,823	$	$ 24,467	$	$ 24,467
Non-current Assets								
Commodity Derivatives		6,853		6,853		15,732		15,732
Current Liabilities								
Commodity Derivatives								
Non-current Liability								
Commodity Derivatives		(9,849)		(9,849)		(4,367)		(4,367)
Total	$	$ 41,827	$	$ 41,827	$	$ 35,832	$	$ 35,832

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects the carrying value, as recorded in our Consolidated Balance Sheet, and fair value of our debt financial instruments which we classified as Level 2 at September 30, 2011 (in thousands):

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior Credit Facility	$ 79,500	$ 79,500	$	$
3.25% Convertible Senior Notes due 2026	24,837	25,970	167,086	173,478
5.0% Convertible Senior Notes due 2029	185,754	196,388	179,171	212,164
8.875% Senior Notes due 2019	275,000	259,875		
Total debt	$ 565,091	$ 561,733	$ 346,257	$ 385,642

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 9 Commitments and Contingencies

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

On July 9, 2010, the sub-lessee agreed to reimburse us for one half of any sums for which we may be cast in judgment in this lawsuit in any final non-appealable judgment, and further agreed to reimburse us for one half of the cash bond. We reduced our accrual by $4.2 million in the third quarter of 2010.

On March 23, 2011, the State of Louisiana Second Circuit Court of Appeals issued an opinion which affirmed the trial court s judgment against us and amended the judgment to make both us and the sub-lessee responsible for the money judgment. On June 10, 2011, we filed an application for writ of certiorari with the Supreme Court of Louisiana which was denied on September 23, 2011. On October 13, 2011, the money judgment of $4.4 million, including interest, was paid to the plaintiffs.

NOTE 10 Acquisitions and Divestitures

On December 30, 2010, we sold the shallow rights in certain of our non-core properties located in Northwest Louisiana and East Texas for approximately $65 million with an effective date of July 1, 2010. We have retained all of the deep drilling rights on these divested properties, including the rights to both the Haynesville Shale and Bossier Shale formations. In the second quarter of 2011, we issued our final settlement statement resulting in a gain of less than $0.1 million.

In January 2011, we sold other non-core assets for which we recorded a $0.2 million gain.

Through September 30, 2011, we acquired approximately 74,000 acres in leases in the Tuscaloosa Marine Shale, an oil-rich formation that straddles the middle of Louisiana and part of southern Mississippi. We paid approximately $14 million in cash for the acreage.

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Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

- planned capital expenditures;
- future drilling activity;
- our financial condition;
- business strategy, including our ability to successfully transition to more liquids-focused operations;
- the market prices of oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- financial market conditions and availability of capital;
- production;
- hedging arrangements;
- future cash flows and borrowings;

litigation matters;

pursuit of potential future acquisition opportunities;

sources of funding for exploration and development;

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

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

the creditworthiness of our financial counterparties and operation partners;

the securities, capital or credit markets;

our ability to repay our debt; and

other factors discussed below and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2010, and in our other public filings, press releases and discussions with management.

Overview

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

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

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

We place primary emphasis on our internally generated cash flow from operating activities in managing our business. Our 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. Although such pricing factors are largely beyond our control, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Business Strategy

Our business strategy is to provide long term growth in reserves and cash flow on a cost-effective basis. We focus on adding reserve value through the development of our large, relatively low-risk Haynesville Shale, Eagle Ford Shale and Cotton Valley Taylor Sand trend acreage. We currently expect to commence exploration activities on our recently acquired Tuscaloosa Marine Shale acreage in 2012. We regularly evaluate possible acquisitions of prospective acreage and oil and gas drilling opportunities.

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

Develop existing property base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest potential rate of return. We intend to concentrate on developing our multi-year inventory of drilling locations on our acreage in the Eagle Ford Shale, Haynesville Shale and Cotton Valley Taylor Sand trend. We estimate that our Eagle Ford Shale acreage currently includes approximately 385 net unrisked drilling locations on 100 acre spacing. Our Haynesville Shale acreage currently includes approximately 1,000 net unrisked drilling locations based on anticipated well spacing of 80 acres, and our Cotton Valley Taylor Sand horizontal inventory includes approximately 189 net unrisked drilling locations based on anticipated well spacing of 160 acres.

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

Expand acreage position in shale plays. As of September 30, 2011, we have acquired approximately 74,000 net acres in the Tuscaloosa Marine Shale trend in Southeastern Louisiana and Southwestern Mississippi and have added 4,000 net acres since September 30, 2011, bringing our total net acreage figure as of October 30, 2011 to 78,000 net acres. 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 areas that exhibit similar characteristics to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on maximizing cash flow margins. We intend to maximize cash flow margins by focusing on higher-margin oil development in the Eagle Ford Shale trend in South Texas and the Cotton Valley Taylor Sand trend in our South Henderson field in Rusk County, Texas. In the current commodity price environment, our Eagle Ford Shale assets offer more attractive cash flow margins than our natural gas assets. From the third quarter of 2010 to the third quarter of 2011, we lowered our lease operating costs on a consolidated basis from $0.74 per Mcfe to $0.51 per Mcfe attributable to our lower cost Haynesville Shale development and divesting higher cost

mature assets. We expect this trend to continue as it relates to our natural gas properties.

Maintain financial flexibility. As of September 30, 2011, we had a borrowing base of $225 million under our Senior Credit Facility, of which $79.5 million was outstanding. In October 2011, we entered into the Sixth Amendment which increased our borrowing based to $275 million. We have historically funded growth through cash flow from operations, equity and equity-linked security issuances, debt security issuances, divestments of non-core assets and strategic joint ventures. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically fixed price swaps and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy.

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Primary Operating Areas

Eagle Ford Shale

During the second half of 2010, we commenced drilling operations on our acreage in the Eagle Ford Shale trend. Our leasehold position is located in both La Salle and Frio counties, Texas. During the first nine months of 2011, we conducted drilling operations on approximately 18 gross (12 net) operated Eagle Ford Shale trend wells. During the last quarter of 2011, we plan to conduct drilling operations on approximately four gross (three net) Eagle Ford Shale/Buda Lime formation wells on our properties in South Texas.

Haynesville Shale

Our relatively low risk development drilling program in the Haynesville Shale trend is primarily centered in and around Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We hold approximately 131,000 gross (86,000 net) acres producing from and prospective for the Haynesville Shale as of September 30, 2011. As of September 30, 2011, we conducted drilling operations on 12 wells in the trend with a 100% success rate. Haynesville Shale wells produced average net volumes of approximately 69,200 Mcfe per day in the third quarter of 2011, or approximately 60% of our total oil and gas production for the quarter ended September 30, 2011.

Core Haynesville Shale

Our core Haynesville Shale drilling program is primarily concentrated in the Bethany-Longstreet and Greenwood-Waskom fields in Caddo and DeSoto Parishes in northwest Louisiana. Our core Haynesville Shale drilling activity includes both operated and non-operated drilling in and around our core acreage positions in northwest Louisiana. We hold approximately 33,000 gross (16,000 net) acres as of September 30, 2011. Our net production volumes from our core Haynesville Shale wells totaled approximately 53,500 Mcfe per day in the third quarter of 2011, or approximately 46% of our total production for the quarter ended September 30, 2011.

Shelby Trough / Angelina River Trend

Our properties in the Shelby Trough/Angelina River trend, where we are the operator of the vast majority of our drilling activities, are primarily located in Nacogdoches, Angelina and Shelby counties in East Texas. We currently hold approximately 35,000 gross (28,000 net) acres as of September 30, 2011. Our net production volumes from our Shelby Trough wells totaled approximately 10,500 Mcfe per day in the third quarter of 2011, or approximately 9% of our total production for the quarter ended September 30, 2011. During the last quarter of 2011, we plan to conduct drilling operations on one well in the Shelby Trough/Angelina River Trend area.

Cotton Valley Taylor Sand

We completed one horizontal Cotton Valley Taylor Sand wells on our acreage position in the South Henderson field of East Texas in the quarter. It had an average initial production rate of 9.360 Mmcfe per day and 160barrels of oil per day. We have approximately 7,000 net acres prospective for the Cotton Valley Taylor Sand in the South Henderson field. Net production volumes from our Cotton Valley Taylor Sand wells totaled approximately 16,900 Mcfe per day in the third quarter of 2011, or approximately 15% of our total oil and gas production for the quarter ended September 30, 2011. During the fourth quarter of 2011, we plan to conduct completion operations on two Cotton Valley Taylor Sand wells in the South Henderson field.

Overview of Third Quarter 2011 Results

Third Quarter 2011 financial and operating results include:

- We increased our average oil and natural gas production volumes to 116,200 Mcfe per day for the third quarter of 2011, representing an increase of 27% from 91,665 Mcfe per day for the third quarter of 2010.

- We conducted drilling operations on ten gross (eight net) wells in the third quarter of 2011, including three in the Haynesville Shale and six Eagle Ford Shale and Buda Lime wells in South Texas. We added nine gross (five net) wells to production in the third quarter of 2011. As of September 30, 2011, we had nine gross (five net) wells drilled, but not completed.

Our oil production increased and currently represents 11% of our total production compared to 2% of our total production in the third quarter of 2010.

We reduced our lease operating expense per Mcfe by 31% to $0.51 per Mcfe in the third quarter of 2011 compared to $0.74 per Mcfe in the third quarter of 2010.

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Results of Operations

For the three months ended September 30, 2011, we reported net income applicable to common stock of $12.1 million, or $0.34 per basic share and $0.33 per diluted share, on total revenue of $55.5 million as compared to a net loss applicable to common stock of $226.6 million, or ($6.31) per basic and diluted share, on total revenue of $37.4 million for the three months ended September 30, 2010. The increase in production volumes contributed $11.7 million to the $18.1 million increase in oil and natural gas revenues and higher average realized prices contributed $6.4 million of the increase as compared to the three months ended September 30, 2010. We recorded a $26.5 million gain on derivatives not designated as hedges in the three months ended September 30, 2011 compared to a $22.5 million gain on derivatives not designated as hedges for the three months ended September 30, 2010.

For the nine months ended September 30, 2011, we reported a net loss applicable to common stock of $14.0 million, or $0.39 per basic and diluted share, on total revenue of $149.6 million as compared to a net loss applicable to common stock of $246.9 million, or ($6.88) per basic and diluted share, on total revenue of $112.0 million for the nine months ended September 30, 2010. The increase in production volumes contributed $26.2 million to the $37.0 million increase in oil and natural gas revenues and higher net average realized prices contributed $10.7 million of the increase as compared to the nine months ended September 30, 2010. We recorded a $27.4 million gain on derivatives not designated as hedges in the nine months ended September 30, 2011 compared to a $57.5 million gain on derivatives not designated as hedges for the nine months ended September 30, 2010. The primary difference in results between the periods was the impairment of $234.9 million recorded in 2010 compared to the $1.2 million impairment in 2011.

Oil and Natural Gas Revenues

Revenues presented in the table and in the discussion below, represent revenue from sales of our oil and natural gas production volumes.

Summary Operating Information:

	Three Months Ended September 30,				Nine Months Ended September 30,			
(In thousands, except for price data)	**2011**	**2010**	**Variance**		**2011**	**2010**	**Variance**	
Revenues:								
Natural gas	$ 38,381	$ 35,060	$ 3,321	9%	$ 111,371	$ 104,751	$ 6,620	6%
Oil and condensate	17,156	2,383	14,773	620%	37,518	7,169	30,349	423%
Natural gas, oil and condensate	55,537	37,443	18,094	48%	148,889	111,920	36,969	33%
Operating revenues	55,542	37,424	18,118	48%	149,644	112,041	37,603	34%
Operating expenses	55,366	275,906	(220,540)	(80%)	149,785	384,631	(234,846)	(61%)
Operating income (loss)	176	(238,482)	238,658	100%	(141)	(272,590)	272,449	100%
Natural gas (MMcf)	9,468	8,235	1,233	15%	27,562	24,202	3,360	14%
Oil and condensate (MBbls)	204	33	171	518%	418	97	321	331%
Total (Mmcfe)	10,690	8,433	2,257	27%	30,073	24,785	5,288	21%
Average daily production (Mcfe/d)	116,200	91,665	24,535	27%	110,157	90,786	19,371	21%
Average realized sales price per unit:								
Natural gas (per Mcf)	$ 4.05	$ 4.26	$ (0.21)	(5%)	$ 4.04	$ 4.33	$ (0.29)	(7%)
Oil and condensate (per Bbl)	84.18	72.30	11.88	16%	89.65	73.85	15.80	21%
Total (per Mcfe)	5.20	4.44	0.76	17%	4.95	4.52	0.43	10%

Revenues from operations increased for the three months ended September 30, 2011 compared to the same period in 2010 as a result of a 27% increase in production coupled with a 17% net increase in average realized sales price. Revenues from operations increased for the nine months ended September 30, 2011 compared to the same period in 2010 as a result of a 21% increase in production and a 10% net increase in average realized sales price. The production increase in the three and nine month periods ended September 30, 2011 compared to the same period in 2010 is primarily due to the increase in oil production volumes obtained from our Eagle Ford Shale wells and gas production in our Haynesville Shale properties, partially offset by non-core properties sold in December 2010. For the three months ended September 30, 2010, 6% of our oil and gas revenue was attributable to oil sales whereas for the three months ended September 30, 2011, oil sales contributed 31% to our oil and natural gas revenues.

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For the three months ended September 30, 2011, our average realized price for natural gas was $4.05 per Mcf. For the same period in 2010, our average realized price for natural gas was $4.26 per Mcf. For the three months ended September 30, 2011, our average realized price for natural gas was $4.76 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives. For the same period in 2010, our average realized price for natural gas was $5.03 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives.

For the nine months ended September 30, 2011, our average realized price for natural gas was $4.04 per Mcf. For the same period in 2010, our average realized price for natural gas was $4.33 per Mcf. For the nine months ended September 30, 2011, our average realized price for natural gas was $4.74 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives. For the same period in 2010, our average realized price for natural gas was $4.98 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives.

The difference between our average realized prices inclusive of the hedge realizations in the nine months ended September 30, 2011 and 2010 periods relates to our natural gas collars contracts. As of September 30, 2011, we had 40,000 MMBtu per day hedged at a floor price of $6.00 per MMBtu, and as of September 30, 2010, we had 50,000 MMBtu per day hedged at an average floor price of $6.00 per MMbtu.

For the three months ended September 30, 2011, our average realized price for oil was $84.18 per Bbl. For the same period in 2010, our average realized price for oil was $72.30 per Bbl. For the three months ended September 30, 2011, our average realized price for oil was $92.19 per Bbl, including the effect of the realized gains and losses on our oil derivatives. We did not have any oil derivatives for the same period in 2010.

For the nine months ended September 30, 2011, our average realized price for oil was $89.65 per Bbl. For the same period in 2010, our average realized price for oil was $73.85 per Bbl. For the nine months ended September 30, 2011, our average realized price for oil was $94.51 per Bbl, including the effect of the realized gains and losses on our oil derivatives. We did not have any oil derivatives for the same period in 2010.

Operating Expenses

The following tables present our comparative operating expenses:

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses (in thousands)	**2011**	**2010**	**Variance**		**2011**	**2010**	**Variance**	
Lease operating expenses	$ 5,447	$ 6,280	$ (833)	(13%)	$ 15,565	$ 19,841	$ (4,276)	(22%)
Production and other taxes	1,599	664	935	141%	4,194	2,017	2,177	108%
Transportation	2,795	2,977	(182)	(6%)	7,482	7,619	(137)	(2%)
Exploration	1,638	2,033	(395)	(19%)	6,379	7,639	(1,260)	(16%)

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses per Mcfe	**2011**	**2010**	**Variance**		**2011**	**2010**	**Variance**	
Lease operating expenses	$ 0.51	$ 0.74	$ (0.23)	(31%)	$ 0.52	$ 0.80	$ (0.28)	(35%)
Production and other taxes	0.15	0.08	0.07	88%	0.14	0.08	0.06	75%
Transportation	0.26	0.35	(0.09)	(26%)	0.25	0.31	(0.06)	(19%)
Exploration	0.15	0.24	(0.09)	(38%)	0.21	0.31	(0.10)	(32%)

Lease Operating. Lease operating expense (LOE) for the three and nine months ended September 30, 2011, decreased in comparison to the same periods in 2010 as a result of our sale in December 2010 of our high cost non-core gas properties and a greater percentage of our production volumes coming from our Haynesville Shale wells which carry a lower LOE per unit of production.

On a per unit basis, LOE decreased for the three and nine months ended September 30, 2011 compared to the same periods in 2010 as a result of the sale of higher cost properties in December 2010, a 27% and 21% increase in production volumes for the three and nine months ended September 30, 2011, respectively, and an increasing portion of our production coming from the lower production cost Haynesville Shale wells.

Production and Other Taxes. Production and other taxes for the three months ended September 30, 2011 includes ad valorem tax of $0.7 million and $0.9 million in production tax. The production tax represents $1.2 million current period expense reduced by $0.3 million in Tight Gas Sands (TGS) tax credits. During the comparable period in 2010, production and other taxes for the three months ended September 30, 2010 includes ad valorem tax of $0.9 million and a $0.2 million production tax credit. The production tax represents $0.5 million expense for the three month period reduced by $0.7 million in TGS tax credits.

Production and other taxes for the nine months ended September 30, 2011 includes ad valorem tax of $2.0 million and $2.2 million in production tax. The production tax represents $3.4 million current period expense reduced by $1.2 million in Texas high cost severance tax credits. During the comparable period in 2010, production and other taxes for the nine months ended September 30, 2010 was $2.0 million which includes ad valorem tax of $1.8 million and production tax of $0.2 million. The production tax represents $2.2 million expense for the nine month period reduced by $2.0 million of new TGS tax credits for our wells in Texas and for our horizontally drilled wells in Louisiana.

The increase in production and other taxes in 2011 over 2010 is attributable to production taxes in connection with our new Texas oil wells that are not subject to any production tax abatement and outstanding TGS tax credits claims.

TGS credits allow for reduced and/or eliminated severance taxes in the state of Texas for qualifying wells for up to ten years of production. We accrue for such credits once we have been notified of the State s approval.

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Our Louisiana horizontal wells are eligible for a two year severance tax exemption from the date of first production or until payout of qualified costs, whichever comes first. During the three months ended September 30, 2011, our exempt Louisiana wells began reaching the two year maturity.

Transportation. Transportation expense in the three months and nine months ended September 30, 2011 decreased slightly as compared to the same periods ended September 30, 2010 as a result of a greater percentage of our production being oil and the sale of our non-core properties in December 2010 offset by expenses generated from our new production in the Angelina River Trend. Transportation expense is primarily composed of gas gathering and treating fees. Oil is generally sold at the lease tanks.

Exploration. Exploration expense for the three and nine months ended September 30, 2011 decreased as compared to the same periods in 2010. We recorded a slightly lower undeveloped leasehold cost amortization and lower seismic cost in the three months ended September 30, 2011 compared to the same period in 2010.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses (in thousands)	**2011**	**2010**	**Variance**		**2011**	**2010**	**Variance**	
Depreciation, depletion and amortization	$ 37,348	$ 26,022	$ 11,326	44%	$ 93,234	$ 84,638	$ 8,596	10%
Impairment	142	234,887	(234,745)	(100%)	1,192	234,887	(233,695)	(99%)
General and administrative	6,251	7,275	(1,024)	(14%)	21,829	23,722	(1,893)	(8%)

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses per Mcfe	**2011**	**2010**	**Variance**		**2011**	**2010**	**Variance**	
Depreciation, depletion and amortization	$ 3.49	$ 3.09	$ 0.40	13%	$ 3.10	$ 3.41	$(0.31)	9%
Impairment	0.01	27.85	(27.84)	(100%)	0.04	9.48	(9.44)	(100%)
General and administrative	0.58	0.86	(0.28)	(33%)	0.73	0.96	(0.23)	(24%)

Depreciation, Depletion and Amortization. Depreciation, Depletion and Amortization (DD&A) increased $11.3 million or 44% in the three months ended September 30, 2011 compared to the same period in 2010 principally as the result of a 27% increase in production volumes for the quarter ended September 30, 2011 and a greater percentage of our production volumes coming from operating areas with higher DD&A rates, such as our South Texas oil properties.

The DD&A increased by $8.6 million, or 10%, in the nine months ended September 30, 2011 compared to the same period in 2010 is principally as a result of a 21% increase in production volumes and a greater percentage of our production volumes coming from operating areas with higher DD&A rates, such as our South Texas oil properties.

Impairment. We recorded impairment expense of $1.2 million on two properties in the nine months ended September 30, 2011, the majority related to an increase in asset retirement obligation for a field that is no longer producing. We recorded impairment expense of $234.9 million on several fields in the three and nine months ended September 30, 2010, related mostly to a decreasing projected natural gas price environment resulting in the write down of the carrying values of certain non-core assets. In addition to lower commodity prices, the impairment was a result of our change in forward looking development plans, which focused on the Eagle Ford Shale, core Haynesville Shale in North Louisiana and the Angelina River Trend of the Shelby Trough.

General and Administrative. General and administrative (G&A) expense decreased in the three months ended September 30, 2011, compared to the same period in 2010 primarily as a result of a partial refund of a Louisiana State franchise tax payment made under protest in 2007 and construction overhead recoveries. G&A expense on a per unit basis decreased as a result of a 27% increase in our daily production volumes in the third quarter of 2011 as compared to the third quarter of 2010. Stock based compensation expense, which is a non-cash item, decreased to $1.3 million in the third quarter of 2011 from $1.5 million in 2010.

G&A expense decreased in the nine months ended September 30, 2011, compared to the same period in 2010. The decrease relates primarily to the partial refund and final settlement of a Louisiana State franchise tax payment made under protest in 2007, construction overhead recoveries, decreases in stock based compensation and consulting cost. The G&A during the nine months ended September 30, 2010 also included the cost of a consulting agreement related to the resignation of an executive officer. G&A expense on a per unit basis decreased as a result of a 21% increase in our daily production volumes in the first nine months of 2011 as compared to the first nine months of 2010. Stock based compensation expense, which is a non-cash item, decreased to $4.5 million in the nine months ended September 30, 2011 from $5.5 million in 2010.

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Operating Expenses (in thousands)	Three Months Ended September 30, 2011	2010	Variance		Nine Months Ended September 30, 2011	2010	Variance	
Gain on sale of assets	$	$	$		$ (236)	$	$ (236)	(100%)
Other	146	(4,232)	4,378	103%	146	4,268	(4,122)	(97%)

Operating Expenses per Mcfe	Three Months Ended September 30, 2011	2010	Variance		Nine Months Ended September 30, 2011	2010	Variance	
Gain on sale of assets	$	$	$		$ (0.01)	$	$ (0.01)	(100%)
Other	0.01	(0.50)	0.51	102%		0.17	(0.17)	(100%)

Gain on sale of assets. We recorded a gain of $0.2 million on the sale on non-core oil and gas properties in the nine months ended September 30, 2011.

Other. In the first quarter of 2010, we accrued the full amount of $8.5 million as a reserve for litigation relating to the lawsuit with a lessee, *Hoover Tree Farm LLC vs. Goodrich Petroleum Company LLC* filed in Caddo Parish Louisiana as described in Note 9-Commitments and Contingencies to our consolidated financial statements contained in this report.

On July 9, 2010, the sub-lessee agreed to reimburse us for one half of any sums for which we may be cast in judgment in this lawsuit in any final non-appealable judgment, and further agreed to reimburse us for one half of the cash bond. We reduced our accrual by $4.2 million in the third quarter of 2010.

On March 23, 2011, the State of Louisiana Second Circuit Court of Appeals issued an opinion which affirmed the trial court s judgment against us and amended the judgment to make both us and the sub-lessee responsible for the money judgment. On June 10, 2011, we filed an application for writ of certiorari with the Supreme Court of Louisiana which was denied on September 23, 2011. On October 13, 2011, the money judgment of $4.4 million, including interest, was paid to the plaintiffs.

Other Income (Expense)

The following table presents our comparative other income (expense) for the periods presented (in thousands):

Other income (expense) (in thousands):	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Interest expense	$ (13,022)	$ (9,154)	$ (36,815)	$ (27,469)
Interest income and other	21	11	43	117
Gain on derivatives not designated as hedges	26,453	22,494	27,397	57,543
Average funded borrowings	574,125	393,500	517,916	393,500
Average funded borrowings adjusted for debt discount	539,515	339,444	479,345	335,511
Weighted average interest rate	9.6%	10.7%	10.3%	10.9%

Interest Expense. Interest expense in the three and nine months ended September 30, 2011 increased compared to the three and nine months ended September 30, 2010, as a result of the higher average level of outstanding debt in the three and nine months ended September 30, 2011. The higher average level of debt resulted from the issuance of our $275 million 2019 Notes. Non-cash interest of $3.5 million is included in the $13.0 million interest expense reported for the three months ended September 30, 2011. Non-cash interest of $11.7 million is included in the $36.8 million interest expense reported for the nine months ended September 30, 2011.

Gain on Derivatives Not Designated as Hedges. Gain on derivatives not designated as hedges for the three months ended September 30, 2011 consists of a realized gain of $8.3 million and an unrealized gain of $18.2 million for the change in fair value of our oil and natural gas derivative contracts. The average futures strip prices for oil and natural gas were lower in the current period compared to the previous quarter resulting in an unrealized gain in the third quarter of 2011. As a comparison, gain on derivatives not designated as hedges for the three months ended September 30, 2010, included a realized gain of $6.3 million and an unrealized gain of $16.2 million for the changes in fair value of our natural gas derivative contracts.

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Gain on derivatives not designated as hedges for the nine months ended September 30, 2011, consists of a realized gain of $21.4 million and an unrealized gain of $6.0 million for the change in fair value of our oil and natural gas derivative contracts. The average futures strip prices for oil and natural gas were lower in the current period compared to year end 2010, resulting in an unrealized gain in the current period. As a comparison, gain on derivatives not designated as hedges for the nine months ended September 30, 2010, included a realized gain of $15.7 million and an unrealized gain of $41.9 million for the changes in fair value of our natural gas 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 taxes. We recorded no income tax benefit for the three and nine months ended September 30, 2011. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2010 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of September 30, 2011.

Liquidity and Capital Resources

Our primary sources of liquidity during the first nine months of 2011 were from cash on hand, cash flow from operating activities, available borrowings under our Senior Credit Facility and our issuance of the 2019 Notes. We used cash primarily to fund our capital spending program, retire debt and pay preferred stock dividends. Our primary sources of cash during the first nine months of 2010 were cash flow from operating activities and proceeds from the sale of assets. We used cash primarily to fund our capital spending program, and pay preferred stock dividends. We expect to finance our estimated capital expenditures for the remainder of 2011 through a combination of cash on hand, cash from operating activities and availability under our Senior Credit Facility.

Our total 2011 capital expenditure budget of $315 million represents an increase from our initial budget of $235 million. We expect capital spending by area to be approximately 56% for Eagle Ford Shale Trend, 28% for Haynesville Shale Trend, 10% for Cotton Valley Taylor Sand Trend and 6% for other.

We have in place a $600 million Senior Credit Facility, which we entered into with a syndicate of United States and International lenders, and as of September 30, 2011 we had a borrowing base of $225 million under our Senior Credit Facility, of which $79.5 million was outstanding. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The Fourth Amendment became effective upon the closing of the issuance and sale of our 2019 Notes, which occurred on March 2, 2011, and the placement of $175 million of net proceeds in an escrow account to be used for the redemption or earlier repurchase of all of our outstanding 2026 Notes. In October 2011, we entered into the Sixth Amendment which increased our borrowing based to $275 million. As of September 30, 2011, we were in compliance with existing covenants, as amended.

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

Funding alternatives available to us include:

- sale of non-core assets,
- bring in joint venture partners in core Haynesville and/or Eagle Ford Shale acreage,
- availability under our Senior Credit Facility, and
- issuance of debt or equity securities.

Our Senior Credit Facility matures on July 31, 2014. In addition, holders of our remaining 2026 Notes have the right to require us to purchase some or all of such notes at par on December 1, 2011. Because the conversion price of those notes is substantially above the recent trading price of our common stock, we expect that it is more likely than not that some or all of these 2026 Notes will be put to us for repurchase on such date.

Pursuant to the terms of our Senior Credit Facility, we have $25.1 million remaining in escrow related funding the redemption of the remaining outstanding 2026 Notes. We intend to use these escrowed funds to redeem all of the remaining outstanding 2026 Notes on or before December 1, 2011 if put to us by the holders of the Notes. As of September 30, 2011, we have classified the remaining 2026 Notes of $24.8 million as a current liability.

We have also supported our cash flows by entering into derivative positions as of September 30, 2011 covering approximately 55% of our projected oil and natural gas sales volumes for the remainder of 2011 and 2012. See Note 7-Derivative Activities in the Notes to Consolidated Financial Statements under Part 1 Item 1 of this Form 10-Q.

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Cash Flows

The following table presents our comparative cash flow summary for the periods reported (in thousands):

	Nine months ended September 30,		
	2011	2010	Variance
Cash flow statement information:			
Net cash:			
Provided by operating activities	$ 109,937	$ 76,962	$ 32,975
Used in investing activities	(287,895)	(184,078)	(103,817)
Provided by (used in) financing activities	163,611	(5,435)	169,046
Decrease in cash and cash equivalents	$ (14,347)	$ (112,551)	$ 98,204

Operating activities. Net cash provided by operating activities increased $33.0 million to $109.9 million for the nine months ended September 30, 2011, from $77.0 million for the comparable period in 2010 period as more cash was realized from derivative settlements and an increased percentage of our production from oil, which is sold at a higher price to natural gas. For the nine months ended September 30, 2011 eight percent of our production was attributed to oil compared to two percent in the same period of 2010.

Investing activities. Net cash used in investing activities was $287.9 million for the nine months ended September 30, 2011. We conducted drilling operations on 36 gross wells including 12 wells in the Haynesville Shale and 18 wells in the Eagle Ford Shale and six wells in other areas in the first nine months of 2011. In comparison, we conducted drilling operations on 40 gross wells, 35 of which penetrated the Haynesville Shale during the first nine months of 2010. The increase in the investing amount in 2011 compared to 2010 reflects higher completion costs in 2011. The $287.9 million used in investing activities during 2011 consists of $288.1 million related to capital expenditures offset by $0.2 million from the sale of non-core assets. Of the $288.1 million capital expenditures spent in the nine months ended September 30, 2011, approximately $257.2 million was for drilling and completion activities, $19.0 million was for leasehold acquisition, $10.3 million was for facilities and infrastructure, $1.0 million was for capital workover and $0.6 million was for furniture, fixtures and equipment.

Financing activities. Net cash provided by financing activities was $163.6 million for the nine months ended September 30, 2011, compared to cash used in financing activities of $5.4 million for the same period in 2010. The net cash provided by financing activities for the nine months ended September 30, 2011 consisted of proceeds from the issuance our 2019 Notes and net borrowings under our Senior Credit Facility partially offset by the redemption of a portion of our 2026 Notes, cash restricted for the redemption of our 2026 Notes, financing cost on the issuance of 2026 Notes and preferred stock dividends.

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (the Senior Credit Facility) that replaced our previous facility. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The primary conditions for the effectiveness of the Fourth Amendment were (i) the closing of the issuance and sale of our 8.875% Notes due 2019 (the 2019 Notes), and (ii) the placement of not less than $175 million of net proceeds from the sale of the 2019 Notes in an escrow account with the lenders to be used for the redemption or earlier repurchase of all our outstanding 3.25% Convertible Senior Notes due 2026 (the 2026 Notes), both of which occurred on March 2, 2011.

Total lender commitments under the Senior Credit Facility are $600 million subject to borrowing base limitations as of September 30, 2011 of $225 million. The Senior Credit Facility matures on July 1, 2014 (subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029 (the 2029 Notes). Revolving borrowings under the Senior Credit Facility are limited to, and subject to, periodic redeterminations of 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 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. As of September 30, 2011, we had $79.5 million outstanding under the Senior Credit Facility. Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

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The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used here, but not defined, have the meanings assigned to them in the Senior Credit Facility. In October 2011, we entered into a Sixth Amendment to the Senior Credit Facility which amended the EBITDAX annualized calculation and increased the borrowing base to $275 million. The primary financial covenants include:

Current Ratio of 1.0/1.0;

Interest Coverage Ratio of EBITDAX of not less than 2.5/1.0 for the trailing four quarters or when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters. The interest for such period to apply solely to the cash portion of interest expense; and

Total Debt no greater than 4.0 times EBITDAX for the trailing four quarters. Total Debt used in such ratio to be reduced by the amount of any restricted cash held in an escrow account established for the benefit of the lenders and dedicated to the redemption or prepayment of the 2026 Notes, the 2029 Notes or the 2019 Notes; provided that such ratios, when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters.

As defined in the Senior Credit Facility, EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense, stock based compensation 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.

We were in compliance with all the financial covenants of the Senior Credit Facility as of September 30, 2011.

8.875% Senior Notes due 2019

On March 2, 2011, we sold $275 million of our 2019 Notes. The 2019 Notes mature on March 15, 2019, unless earlier redeemed or repurchased. The 2019 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2019 Notes accrue interest at a rate of 8.875% annually, and interest is paid semi-annually in arrears on March 15 and September 15. The 2019 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

Before March 15, 2014, we may on one or more occasions redeem up to 35% of the aggregate principal amount of the 2019 Notes at a redemption price of 108.875% of the principal amount of the 2019 Notes, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings. On or after March 15, 2015, we may redeem all or a portion of the 2019 Notes at redemption prices (expressed as percentages of principal amount) equal to (i) 104.438% for the twelve-month period beginning on March 15, 2015; (ii) 102.219% for the twelve-month period beginning on March 15, 2016 and (iii) 100.000% on or after March 15, 2017, in each case plus accrued and unpaid interest to the redemption date. In addition, prior to March 15, 2015, we may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2019 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem or retire such capital stock; (iii) sell assets, including the capital stock of our restricted subsidiaries; (iv) pay dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. These covenants are subject to a number of important exceptions and qualifications. At any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the indenture governing the 2019 Notes) has occurred and is continuing, many of these covenants will terminate.

Interest expense recognized relating to the contractual interest rate and amortization of financing cost for the three and nine months ended September 30, 2011 was $6.3 million and $14.6 million, respectively. The effective interest rate on the liability component of the 2019 Notes was 9.1% and 9.2% for the three and nine month periods ended September 30, 2011, respectively.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of our 2029 Notes. The 2029 Notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The 2029 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2029 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 2029 Notes on September 28, 2009.

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Before October 1, 2014, we may not redeem the 2029 Notes. On or after October 1, 2014, we may redeem all or a portion of the 2029 Notes for cash, and the investors may require us to repurchase the 2029 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.

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

The 2029 Notes are convertible into shares of our common stock at a rate equal to 28.8534 shares per $1,000 principal amount of 2029 Notes (equal to an initial conversion price of approximately $34.66 per share of common stock).

We separately account for the liability and equity components of the 2029 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. As of September 30, 2011, the $218.5 million aggregate principal amount of the 2029 Notes was carried on the balance sheet at $185.8 million with a debt discount balance of $32.7 million. As of December 31, 2010, the $218.5 million aggregate principal amount of the 2029 Notes was carried on the balance sheet at $179.2 million with a debt discount of $39.3 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 debt discount and financing cost for the three and nine months ended September 30, 2011, was $5.2 million and $15.5 million, respectively. The effective interest rate on the liability component of the 2029 Notes was 11.1% and 11.4% for the three and nine month periods ended September 30, 2011, respectively. The 2029 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

3.25% Convertible Senior Notes Due 2026

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

During the nine months ended September 30, 2011, we repurchased $149.9 million of our 2026 Notes using a portion of the net proceeds from the issuance of our 2019 Notes. We paid premiums of 101.25%, 100.75% and 100.5% of face value in addition to accrued interest. We recorded each of the three and nine months ended September 30, 2011, a $0.1 million gain on the early extinguishment of debt related to the repurchase. Due to the repurchases, the debt discount was reduced to $0.2 million as of September 30, 2011 to be amortized over the next two months. Under the terms of our Senior Credit Facility, we have deposited in escrow $25.1 million to be used for the redemption of the remaining outstanding 2026 Notes.

Holders may present to us for redemption the remaining outstanding 2026 Notes on or before December 1, 2011. If the holders do not present the notes to us for redemption by December 1, 2011 they may not be redeemed until December 1, 2016. As of September 30, 2011, we have classified the 2026 Notes as a current liability. The balance not redeemed by December 1, 2011 will be reclassified as a long-term liability.

Interest expense relating to the contractual interest rate and amortization of debt discount and financing cost relating to the 2026 Notes for the three and nine months ended September 30, 2011 was $0.5 million and $3.9 million, respectively. The effective interest rate on the liability component of the 2026 Notes was 8.7% and 9.1% for the three and nine month periods ended September 30, 2011, respectively.

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements which were prepared in accordance with generally accepted accounting principles in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We believe that certain accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements. Our Annual Report on Form 10-K for the year ended December 31, 2010, includes a discussion of our critical accounting policies and there have been no material changes to such policies during the nine months ended September 30, 2011.

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Item 3 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 in the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Any decrease in domestic crude oil and gas prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis.

We enter into futures contracts or other derivative agreements from time to time to manage the 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 production. As of September 30, 2011, the commodity hedges we utilized were in the form of:

(a) collars, where we receive a fixed price and pay a floating price, based on NYMEX or specific transfer point quoted prices;

(b) swaps, where we receive a fixed price and pay a floating price, based on NYMEX or specific transfer point quoted prices; and

(c) swaptions, where we grant the counterparty the right but not the obligation to enter into a swap agreement by a specific date.

During the third quarter of 2011, we entered into the following new derivative contracts.

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 101.50	August 1, 2011	January 31, 2013
Oil swap (BBL)	1,000	$ 101.00	January 1, 2012	December 31, 2012
Oil swaption (BBL)	1,000	$ 101.00	January 1, 2013	December 31, 2013
Oil swaption (BBL)	1,000	$ 101.00	January 1, 2014	December 31, 2014
Natural gas swap (MMBtu)	20,000	$ 5.35	January 1, 2012	December 31, 2012
Natural gas swaption (MMBtu)	20,000	$ 5.35	January 1, 2013	December 31, 2013
Natural gas swaption (MMBtu)	20,000	$ 5.35	January 1, 2014	December 31, 2014

After September 30, 2011, we entered into the following new derivative contracts:

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 97.30	January 1, 2012	December 31, 2012
Oil swaption (BBL)	500	$ 97.30	January 1, 2013	December 31, 2013
Oil swaption (BBL)	500	$ 97.30	January 1, 2014	December 31, 2014

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 2011. The fair value of the natural gas hedging contracts in place at September 30, 2011, resulted in a net asset of $41.8 million. Based on oil and gas pricing in effect at September 30, 2011, a hypothetical 10% increase in oil and gas prices would have increased the derivative asset to $26.4 million, while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $48.1 million. See Note 7-Derivative Activities in the Notes to Consolidated Financial Statements under Part 1 of this Form 10-Q.

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As of September 30, 2011, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, Bank of Montreal, Royal Bank of Canada and JPMorgan Chase Bank, N.A., were as follows:

Contract Type	Daily Volume	Total Volume	Average Floor/Cap		Fair Value at September 30, 2011 (in thousands)
Natural gas collars (MMBtu)					$ 33,845
4Q 2011	40,000	3,680,000	$ 6.00	$7.09	
2012	40,000	14,640,000	$ 6.00	$7.09	
			Fixed Price		
Natural gas swaps (MMBtu)					7,673
2012	20,000	7,320,000	$ 5.35		
Natural gas swaptions (MMBtu)					(6,511)
2013	20,000	7,300,000	$ 5.35		
2014	20,000	7,300,000	$ 5.35		
Oil swaps (BBL)					14,250
4Q 2011	1,500	138,000	$ 100.00	$112.00	
2012	1,500	549,000	$ 101.00	$101.50	
2013	500	15,500	$ 101.50		
Oil swaptions (BBL)					(7,430)
2012	1,000	365,200	$ 100.00	$112.00	
2013	2,000	730,800	$ 100.00	$112.00	
2014	1,000	365,000	$ 101.00		
			Total	$	41,827

The following table summarizes the realized and unrealized gains and losses we recognized on our oil and natural gas derivatives for the three and nine month periods ended September 30, 2011 and 2010.

Oil and Natural Gas Derivatives (in thousands):	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine months Ended September 30, 2011	Nine months Ended September 30, 2010
Realized gain on oil and natural gas derivatives	$ 8,290	$ 6,329	$ 21,402	$ 15,658
Unrealized gain on oil and natural gas derivatives	18,163	16,165	5,995	41,907
Total gain on oil and natural gas derivatives	$ 26,453	$ 22,494	$ 27,397	$ 57,565

Adoption of Comprehensive Financial Reform

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Risk Factors in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

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Item 4 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 Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, 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 September 30, 2011, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

No changes in our system of internal control over financial reporting occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1 Legal Proceedings

A discussion of current legal proceedings is set forth in Part I, Item 1. Financial Statements, under Note 9 Commitments and Contingencies to our consolidated financial statements in this Form 10-Q.

Item 1A Risk Factors

There are no material changes from risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

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Item 6 Exhibits

*10.1	Sixth Amendment to Second Amended and Restated Credit Agreement dated as of October 31, 2011 among Goodrich Petroleum Company, L.L.C., BNP Paribas, as administrative agent, and the lenders party thereto.
*31.1	Certification of 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 of 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 of 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 of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document
*101.LAB	XBRL Labels Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document

* Filed herewith
** Furnished herewith

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GOODRICH PETROLEUM CORPORATION

(Registrant)

Date: November 4, 2011 By: /S/ WALTER G. GOODRICH
Walter G. Goodrich

Vice Chairman & Chief Executive Officer

Date: November 4, 2011 By: /S/ JAN L. SCHOTT
Jan L. Schott

Senior Vice President & Chief Financial Officer

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GOODRICH PETROLEUM CORPORATION LIST OF EXHIBITS TO FORM 10-Q

FOR QUARTER ENDED SEPTEMBER 30, 2011

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