GOODRICH PETROLEUM CORP
Form 10-Q
August 05, 2010
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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 June 30, 2010

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**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	x	Accelerated filer	¨
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 August 2, 2010 was 37,560,798.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(In thousands)

	June 30, 2010 (unaudited)	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 56,472	$ 125,116
Accounts receivable, trade and other, net of allowance	9,765	7,944
Income taxes receivable	4,250	15,438
Accrued oil and gas revenue	13,753	17,206
Fair value of natural gas derivatives	17,607	5,403
Materials inventory	7,644	662
Prepaid expenses and other	1,555	1,609
Total current assets	111,046	173,378
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,462,102	1,339,462
Furniture, fixtures and equipment	4,606	3,985
	1,466,708	1,343,447
Less: Accumulated depletion, depreciation and amortization	(734,695)	(669,463)
Net property and equipment	732,013	673,984
Fair value of natural gas derivatives	13,746	
Deferred tax assets	7,260	4,700
Deferred financing cost	6,979	8,212
TOTAL ASSETS	$ 871,044	$ 860,274
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 36,522	$ 35,079
Accrued liabilities	40,826	25,308
Deferred tax liabilities current	7,260	4,700
Accrued abandonment costs	5,035	4,574
Fair value of natural gas basis derivatives	486	
Fair value of interest rate derivatives		1,087
Total current liabilities	90,129	70,748
LONG-TERM DEBT	338,091	330,147
Accrued abandonment costs	14,000	13,716
Fair value of natural gas derivatives		278

Total liabilities	442,220	414,889
Commitments and contingencies (See Note 10)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized: Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 shares	2,250	2,250
Common stock: $0.20 par value, 100,000,000 shares authorized; issued and outstanding 37,557,314 and 37,452,023 shares, respectively	7,187	7,166
Treasury stock (670 and 19,915 shares, respectively)	(9)	(411)
Additional paid in capital	640,643	637,335
Accumulated deficit	(221,247)	(200,955)
Total stockholders equity	428,824	445,385
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 871,044	$ 860,274

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, Except Per Share Amounts)

(Unaudited)

	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
REVENUES:				
Oil and gas revenues	$ 34,051	$ 26,234	$ 74,477	$ 54,674
Other	111	29	140	50
	34,162	26,263	74,617	54,724
OPERATING EXPENSES:				
Lease operating expense	6,329	6,984	13,561	15,980
Production and other taxes	390	1,049	1,353	2,537
Transportation	2,189	2,591	4,642	5,179
Depreciation, depletion and amortization	28,403	36,537	58,616	70,195
Exploration	2,627	2,959	5,606	5,179
Impairment of oil and gas properties		23,490		23,490
General and administrative	7,001	6,713	16,447	13,770
Gain on sale of assets		(113)		(113)
Other			8,500	
	46,939	80,210	108,725	136,217
Operating loss	(12,777)	(53,947)	(34,108)	(81,493)
OTHER INCOME (EXPENSE):				
Interest expense	(9,195)	(5,298)	(18,315)	(10,506)
Interest income and other	53	202	106	448
Gain on derivatives not designated as hedges	320	2,556	35,049	39,562
	(8,822)	(2,540)	16,840	29,504
Loss before income taxes	(21,599)	(56,487)	(17,268)	(51,989)
Income tax benefit		21,505		20,151
Net loss	(21,599)	(34,982)	(17,268)	(31,838)
Preferred stock dividends	1,512	1,512	3,024	3,024
Net loss applicable to common stock	$ (23,111)	$ (36,494)	$ (20,292)	$ (34,862)
PER COMMON SHARE				
Net loss applicable to common stock - basic	$ (0.64)	$ (1.02)	$ (0.57)	$ (0.97)
Net loss applicable to common stock - diluted	$ (0.64)	$ (1.02)	$ (0.57)	$ (0.97)
Weighted average common shares outstanding - basic	35,918	35,937	35,888	35,953
Weighted average common shares outstanding - diluted	35,918	35,937	35,888	35,953

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six months ended June 30, 2010	Six months ended June 30, 2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (17,268)	$ (31,838)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	58,616	70,195
Unrealized (gain) loss on derivatives not designated as hedges	(26,829)	8,265
Deferred income taxes		(20,116)
Exploration	1,005	101
Amortization of leasehold costs	3,190	2,901
Impairment of oil and gas properties		23,490
Stock based compensation (non-cash)	3,989	3,203
Gain on sale of assets		(113)
Amortization of debt discount and finance cost	9,495	4,621
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	9,357	468
Accrued oil and gas revenue	3,453	2,700
Materials inventory	(6,982)	316
Prepaid expenses and other	357	(2,242)
Accounts payable	1,443	951
Accrued liabilities	7,827	471
Net cash provided by operating activities	47,653	63,373
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(112,391)	(180,193)
Proceeds from sale of assets		148
Net cash used in investing activities	(112,391)	(180,045)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Exercise of stock options and warrants	10	
Debt issuance costs	(318)	(1,802)
Preferred stock dividends	(3,024)	(3,024)
Other	(574)	(682)
Net cash used in financing activities	(3,906)	(5,508)
DECREASE IN CASH AND CASH EQUIVALENTS	(68,644)	(122,180)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	125,116	147,548
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 56,472	$ 25,368

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Significant Accounting Policies

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

The consolidated financial statements of the Company included in this 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 the Company s Annual Report on Form 10-K for the year ended December 31, 2009. The results of operations for the three and six months ended June 30, 2010, are not necessarily indicative of the results to be expected for the full year.

Reclassifications Certain reclassifications of prior year balances have been made to conform them to current year presentation. These reclassifications have no impact on net 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.

Materials inventory Materials inventory consists of casing and tubulars that are expected to be used in our 2010 Capital Drilling Program. Materials 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 for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. We do not designate our derivative contracts as hedges accordingly, changes in fair value are reflected in earnings. See Note 8 Derivatives.

Income Taxes We account for income taxes, as required, under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. See Note 6 Income Taxes.

New Accounting Pronouncements

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

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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

NOTE 2 Resignation of Executive Officer

In March 2010, an officer of the Company resigned. The provisions of the Resignation Agreement dated March 24, 2010 consisted primarily of the following:

Term life of 60,000 fully vested options was modified;

Accelerated vesting of 25,000 shares of restricted stock; and

Execution of a consulting agreement for six months through September 2010.

The Company recognized additional expense related to the agreement of approximately $0.9 million during the six months ended June 30, 2010.

NOTE 3 Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the period ending June 30, 2010, is as follows (in thousands):

	June 30, 2010
Beginning balance	$ 18,290
Liabilities incurred	21
Liabilities settled or sold	
Accretion expense	724
Ending balance	$ 19,035
Current liability	$ 5,035
Long term liability	$ 14,000

NOTE 4 Long-Term Debt

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

	June 30, 2010	December 31, 2009
Senior Credit Facility	$	$
3.25% Convertible Senior Notes due 2026	175,000	175,000
Debt discount on 3.25% Convertible Senior Notes due 2026	(11,914)	(15,915)
5.0% Convertible Senior Notes due 2029	218,500	218,500
Debt discount of 5.0% Convertible Senior Notes due 2029	(43,495)	(47,438)
Total long-term debt	$ 338,091	$ 330,147

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $350 million. The Senior Credit Facility matures on August 31, 2011. The Senior Credit Facility can be further extended to July 1, 2012 upon receipt of proceeds from a refinancing sufficient to prepay the 3.25% convertible senior notes due 2026. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of, the borrowing base. The initial borrowing base was established at $175 million. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50% or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations are made on a semi-annual basis on April 1 and October 1. In connection with the offering of our $218.5 million 5% convertible senior notes due 2029, we entered into an amendment of our Senior Credit Facility to permit the issues of the notes and required payments made on the notes thereafter and to exclude up to $175 million of our 3.25% convertible senior notes due 2026 or our 5% convertible senior notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. On April 20, 2010, the borrowing base was increased to $200 million. We currently have no amounts outstanding under the Senior Credit Facility. Any borrowed funds outstanding under the Senior Credit Facility after August 31, 2010 will be classified as a current liability as long as the 3.25% convertible senior notes due 2026 are outstanding.

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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of not less than 3.0/1.0 for the trailing four quarters; and
- Total Debt no greater than 3.0 times EBITDAX for the trailing four quarters (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Up to $175.0 million of our convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

We were in compliance with all the financial covenants of the Senior Credit Facility as of June 30, 2010.

3.25% Convertible Senior Notes Due 2026

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

Before December 1, 2011, we may not redeem the 2026 Notes. On or after December 1, 2011, we may redeem all or a portion of the 2026 Notes for cash, and the investors may require us to repurchase the 2026 Notes on each of December 1, 2011, 2016 and 2021. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem the 2026 Notes in cash or in certain circumstances redeem in a combination of cash and shares. The 2026 Notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of the 2026 Notes (equal to a base conversion price of approximately $65.94 per share) plus

b) an additional amount of shares per $1,000 of principal amount of the 2026 Notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

We separately account for the liability and equity components of the 2026 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. As of June 30, 2010, the 2026 Notes were carried on the balance sheet at $163.1 million with a debt discount balance of $11.9 million. As of December 31, 2009, the 2026 Notes were carried on the balance sheet at $159.1 million with a debt discount of $15.9 million. The remaining amount of debt discount as of June 30, 2010 will be amortized using the effective interest rate method based upon an original five year term through December 1, 2011.

Interest expense relating to the contractual interest rate and amortization of both financing cost and debt discount relating to the 2026 Notes for the three and six months ended June 30, 2010 was $3.6 million and $7.3 million, respectively. The effective interest rate on the liability component of the 2026 Notes was 9.0% and 9.1% for the three and six month periods ended June 30, 2010, respectively.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes (the 2029 Notes) due in October 2029. The 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.

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 the 2029 Notes in cash or in certain circumstances redeem in a combination of cash and shares. 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 the 2029 Notes (equal to an initial conversion price of approximately $34.66 per share of common stock).

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 June 30, 2010, the $218.5 million 2029 Notes were carried on the balance sheet at $175.0 million with a debt discount balance of $43.5 million. As of December 31, 2009, the $218.5 million 2029 Notes were carried on the balance sheet at $171.1 million with a debt discount of $47.4 million. The debt discount will be amortized using the effective interest rate method based upon an original five year term through October 1, 2014. Interest expense recognized relating to the contractual interest rate and amortization of both financing cost and debt discount for the three and six months ended June 30, 2010 was $5.0 million and $9.9 million, respectively. The effective interest rate on the liability component of the 2029 Notes was 11.4% and 11.6% for the three and six month periods ended June 30, 2010, respectively.

NOTE 5 Net Income Per Common Share

Net income applicable to common stock was used as the numerator in computing basic and diluted income per common share for the six months ended June 30, 2010 and 2009. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(Amounts in thousands, except per share data)			
Basic loss per share:				
Loss applicable to common stock	$ (23,111)	$ (36,494)	$ (20,292)	$ (34,862)
Average shares of common stock outstanding (1)	35,918	35,937	35,888	35,953
Basic loss per share	$ (0.64)	$ (1.02)	$ (0.57)	$ (0.97)
Diluted loss per share:				
Loss applicable to common stock	$ (23,111)	$ (36,494)	$ (20,292)	$ (34,862)
Dividends on convertible preferred stock (2)				
Interest and amortization of loan cost on senior convertible notes, net of tax (3)				
	$ (23,111)	$ (36,494)	$ (20,292)	$ (34,862)
Average shares of common stock outstanding (1)	35,918	35,937	35,888	35,953
Assumed conversion of convertible preferred stock (2)				
Assumed conversion of convertible senior notes (3)				
Stock options and restricted stock (4)				
Average diluted shares outstanding	35,918	35,937	35,888	35,953
Diluted loss per share	$ (0.64)	$ (1.02)	$ (0.57)	$ (0.97)

(1) This amount does not include 1,624,300 shares of common stock outstanding under the Share Lending Agreement. See Note 7 Stockholders Equity.

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

have been dilutive.

(3) Common shares issuable upon assumed conversion of our convertible senior notes amounting to 8,958,394 shares in 2010 and 2,653,927 shares in 2009 and the accrued interest on the 2026 Notes and the 2029 Notes were not included in the computation of diluted loss per share for the periods presented as they would not have been dilutive.

(4) Common shares issuable on assumed conversion of restricted stock and employee stock options for the three and six months ended June 30, 2009 in the amounts of 74,363 and 89,690 shares, respectively, were not included in the computation of diluted loss per common share since their inclusion would not have been dilutive. Common shares issuable on assumed conversion of restricted stock and employee stock options for the three and six months ended June 30, 2010 in the amounts of 7,202 and 49,091 shares, respectively, were not included in the computation of diluted loss per common share since their inclusion would not have been dilutive.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

NOTE 6 Income Taxes

We recorded no income tax expense for the three and six months ended June 30, 2010. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred assets as of June 30, 2010.

As of June 30, 2010, we had no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2009. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to June 30, 2011.

NOTE 7 Stockholders Equity

Restricted Stock

During the three months ended June 30, 2010, 5,436 restricted shares, which had a weighted average grant date value of $27.04 per share, vested. During the six months ended June 30, 2010, 108,544 restricted shares, which had a weighted average grant date value of $20.77 per share, vested.

Share Lending Agreement

In connection with the offering of our 3.25% convertible senior notes due in December 2026, we agreed to lend an affiliate of Bear, Stearns & Co. (BSC) a total of 3,122,263 shares of our common stock under the Share Lending Agreement. Under this agreement, BSC is entitled to offer and sell such shares and use the sale to facilitate the establishment of a hedge position by investors in the notes. BSC will receive all proceeds from the common stock offerings and lending transactions under this agreement. BSC is obligated to return the shares to us in the event of certain circumstances, including the redemption of the notes or the conversion of the notes to shares of our common stock pursuant to the terms of the indenture governing the notes. The Share Lending Agreement also requires BSC to post collateral if its credit rating is below either A3 by Moody s Investors Service (Moody s) or A- by Standard and Poor s (S&P). On March 20, 2008, BSC had 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 March 2008. In May 2008, JP Morgan Chase & Co. completed its acquisition of and assumed all counterparty liabilities of The Bear Stearns Companies, Inc.

The 1,624,300 shares of common stock outstanding as of June 30, 2010, under the Share Lending Agreement, have a fair value of $19.5 million based upon a closing price on June 30, 2010 of $12.00 per share and are required to be returned to us in the future. The shares are treated in basic and diluted earnings per share as if they were already returned and retired. As a result, the shares of common stock lent under the Share Lending Agreement have no impact on the earnings per share calculation.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility, and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of BSC and J.P. Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. Approximately 77,333 options per trading day expired over each of three separate 25 consecutive trading day settlement periods. During 2009, two-thirds of the options expired. The remaining one-third of the options subject to the capped call expired unexercised in the second quarter of 2010. For more information on these transactions, please see our Annual Report on Form 10-K for the year ended December 31, 2009.

NOTE 8 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 total financial impact of our derivative activities on our consolidated Statement of Operations for the three months and six months ended June 30, 2010 was a gain of $0.3 million and $35.0 million, respectively. The gain of $0.3 million for the three months ended June 30, 2010, included $7.1 million in realized gain partially offset by an unrealized loss of $6.8 million. The $35.0 million gain in the six months ended June 30, 2010 consisted of $8.2 million realized gain and $26.8 million unrealized gain.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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. In the three and six months ended June 30, 2010, we hedged approximately 52% and 53%, respectively of our total production volumes. As of June 30, 2010, the commodity derivatives we used were in the form of:

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

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

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

As of June 30, 2010, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, J.P. Morgan or Bank of Montreal, were as follows:

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Average Floor/Cap**		**Fair Value at June 30, 2010 (in thousands)**
Natural gas (MMBtu)					$ 32,107
3Q 2010	50,000	4,600,000	$ 6.00	$7.10	
4Q 2010	50,000	4,600,000	$ 6.00	$7.10	
1Q 2011	40,000	3,600,000	$ 6.00	$7.09	
2Q 2011	40,000	3,640,000	$ 6.00	$7.09	
3Q 2011	40,000	3,680,000	$ 6.00	$7.09	
4Q 2011	40,000	3,680,000	$ 6.00	$7.09	
1Q 2012	40,000	3,640,000	$ 6.00	$7.09	
2Q 2012	40,000	3,640,000	$ 6.00	$7.09	
3Q 2012	40,000	3,680,000	$ 6.00	$7.09	
4Q 2012	40,000	3,680,000	$ 6.00	$7.09	
Basis Swaps (NYMEX/TexOk)			**Average Price (1)**		
Natural gas (MMBtu)					$ (1,240)
3Q 2010	50,000	4,600,000	$ 0.368		
4Q 2010	50,000	4,600,000	$ 0.368		
				Total	$ 30,867

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

The fair value of the natural gas derivative contracts in place at June 30, 2010, that are marked to market resulted in a current asset of $17.6 million, a non-current asset of $13.7 million and a current liability of $0.5 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 9.

The following table summarizes the realized and unrealized gains and losses we recognized on our natural gas derivatives for the three and six month periods ended June 30, 2010 and 2009.

	Three Months Ended June 30.		Six Months Ended June 30.	
Natural Gas Derivatives (in thousands):	**2010**	**2009**	**2010**	**2009**
Realized gain on natural gas derivatives	$ 7,686	$ 27,189	$ 9,329	$ 48,324
Unrealized gain (loss) on natural gas derivatives	(7,364)	(24,380)	25,742	(8,370)
Total gain on natural gas derivatives	$ 322	$ 2,809	$ 35,071	$ 39,954

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Interest Rate Swap

We have no interest rate derivative position as of June 30, 2010, since all of our contracts matured in April 2010.

For the three months ended June 30, 2010, we recognized a loss of less than $0.1 million, including a realized loss of $0.5 million partially offset by an unrealized gain of $0.5 million. For the six months ended June 30, 2010, we recognized a loss of less than $0.1 million, including a realized loss of $1.1 million offset by an unrealized gain of $1.1 million.

NOTE 9 Fair Value of Financial Instruments

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

As of June 30, 2010, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value by applying the income approach and are classified in level 2 as of June 30, 2010 (in thousands):

Description	June 30, 2010 Fair Value Measurements Level 1	Level 2	Level 3	Total
Current Assets				
Commodity Derivatives	$	$ 17,607	$	$ 17,607
Non-current Assets				
Commodity Derivatives		13,746		13,746
Current Liabilities				
Commodity Derivatives		(486)		(486)
Total	$	$ 30,867	$	$ 30,867

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

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 long-term debt financial instruments at June 30, 2010 (in thousands):

	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
3.25% Convertible Senior Notes due 2026	$ 163,086	$ 165,060	$ 159,085	$ 161,438
5.0% Convertible Senior Notes due 2029	175,005	171,741	171,062	226,694
Total long-term debt	$ 338,091	$ 336,801	$ 330,147	$ 388,132

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 10 Commitments and Contingencies

Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC et al. On April 29, 2010 a state court in Caddo Parish, Louisiana, granted a judgment holding the Company solely responsible for the payment of $8.5 million in additional oil and gas lease bonus payments and related interest in an ongoing lawsuit involving the interpretation of a unique oil and gas lease provision. The lease provided for the payment of additional bonuses under certain circumstances in the event higher lease bonuses were paid by the Company, its successors or assigns, within the surrounding area. Without the Company s knowledge, one of the sub-lessees subject to the same lease paid substantially higher bonuses in the area. The Company believes that this ruling was improperly decided and, on July 8, 2010, filed a motion for suspensive appeal. The Company satisfied the requirements for posting a suspensive appeal bond by depositing $8.5 million in July, 2010 with Iberia Bank in Shreveport, Louisiana for the account of the Clerk of Caddo Parish Court. The Company has accrued the full judgment amount, $8.5 million, as of June 30, 2010 which is reflected as Operating Expenses - Other in the Consolidated Statement of Operations.

On July 9, 2010, the sub-lessee agreed to reimburse the Company for one half of any sums for which the Company may be cast in judgment in this lawsuit in any final non-appealable judgment, and further agreed to reimburse the Company for one half of the cash bond. The Company plans to record the effect of this agreement in the third quarter of 2010.

In addition, we are party to other lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our consolidated financial position or results of operations or liquidity. No significant changes to these type lawsuits have occurred since December 31, 2009.

NOTE 11 Related Party Transactions

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

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

NOTE 12 Acquisitions

In April 2010, we acquired leasehold interest within the oil window of the Eagle Ford Shale play in La Salle and Frio Counties, Texas. We paid $10.0 million in upfront cash and have the option to drill to earn the full interest through $44.0 million in carried drilling costs. Subsequent, to this acquisition, we spent $9.5 million to acquire additional leases in the Eagle Ford Shale play resulting in a total investment of $19.5 million at June 30, 2010. The acquisition and subsequent lease costs have been recorded to undeveloped leasehold cost.

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

Forward-Looking Statements

Certain statements in this report, including statements of the future plans, objectives, budgets, legal strategies and proceedings, projected costs and savings, and expected performance are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, that are dependent upon certain events, risks and uncertainties that may be outside our control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to:

- planned capital expenditures;
- future drilling activity;
- our financial condition;
- business strategy;
- the market prices of oil and gas;
- uncertainties about the estimated quantities of oil and gas reserves, including uncertainties associated with the SEC s new rules governing reserve reporting;
- the availability of drilling rigs and equipment or fracturing and pressure pumping crews;
- economic and competitive conditions;
- legislative and regulatory changes;
- financial market conditions and availability of capital;
- production;
- hedging arrangements;
- future cash flows and borrowings;

- litigation matters;
- more stringent environmental laws and increased difficulty in obtaining environmental permits;
- pursuit of potential future acquisition opportunities; and
- sources of funding for exploration and development.

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

These factors, as well as additional factors that could affect our operating results and performance, are described in our Annual Report on Form 10-K for the year ended December 31, 2009, under the headings Business, Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations. We urge you to carefully consider those factors together with the other factors described in this report.

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

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Overview

General

We are an independent oil and gas company engaged in the exploration, exploitation, development and production of oil and natural gas properties primarily in the East Texas and North Louisiana (ETNL) area, which includes the Haynesville Shale play, and South Texas, which includes the Eagle Ford Shale. We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise and related information.

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

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

We place primary emphasis on our internally generated operating cash flow in managing our business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in our Statement of Cash Flows. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses) and impairments.

Our revenues and operating cash flow are dependent on the successful development of our inventory of capital projects with available capital, the timing of commencement and completion of drilling operations, the volume and timing of our production, as well as commodity prices for oil and gas. Such pricing factors are largely beyond our control; however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Eagle Ford Shale

In April 2010, we acquired an average 70% leasehold interest in approximately 50,000 gross (35,000 net) acres within the oil window of the Eagle Ford Shale play in La Salle and Frio Counties, Texas. The purchase price equates to an average of $1,675 per net acre, with approximately $15.0 million in upfront cash and the option to drill to earn the full interest through $44.0 million in carried drilling costs. In light of this acquisition, we are maintaining our 2010 capital expenditure budget of $255.0 million, while reallocating approximately $50.0 million, or about 20% of our total capital expenditure budget, to leasehold, drilling and completion costs associated with the Eagle Ford Shale oil play.

On the majority of our Eagle Ford Shale acreage, we have the drilling rights to the oil-bearing Buda Lime geologic formation, which sits slightly deeper than the Eagle Ford Shale formation. As of June 30, 2010, we had participated in the drilling of our first Buda Lime formation well, and we plan to drill two more Buda Lime formation wells by year-end. As of June 30, 2010, we had conducted drilling operations on our first Eagle Ford Shale formation well, and we plan to drill four to five additional gross wells by year-end.

East Texas and North Louisiana Area

Our drilling program in the ETNL area centers in and around Rusk, Panola, Angelina and Nacogdoches Counties, Texas and DeSoto and Caddo Parishes, Louisiana. We continue to build our acreage position in this area and hold 154,783 gross acres as of June 30, 2010. As of June 30, 2010, we had drilled and completed a cumulative total of 486 gross wells in this area with a success rate in excess of 99%. Our net production volumes from our ETNL wells aggregated approximately 91,762 Mcfe per day in the second quarter of 2010, representing greater than 99% of our total oil and gas production for the period.

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2010 Haynesville Shale Developments

Company Operated Haynesville Shale Drilling Program

We conducted drilling operations on five operated Haynesville Shale horizontal wells during the second quarter of 2010. For the three months ended June 30, 2010, net production from our operated Haynesville Shale wells (horizontal and vertical) averaged approximately 27,464 Mcfe per day, or 30.4% of our total production. We currently anticipate drilling three to five additional operated Haynesville Shale horizontal wells in the last half of 2010.

Chesapeake Haynesville Shale Joint Development

Through our joint development arrangement with Chesapeake Energy Corporation (Chesapeake), which covers certain portions of our acreage in North Louisiana, we had participated in drilling operations of 36 wells with 24 wells on line and producing through June 30, 2010. For the remainder of 2010, we and Chesapeake plan to utilize two rigs to conduct drilling operations on approximately five to seven additional Haynesville Shale horizontal wells to be operated by Chesapeake. For the second quarter of 2010, net production from the joint development averaged 18,010 Mcfe per day.

Company Operated Cotton Valley Taylor Sand Program

During 2009 we commenced a horizontal drilling program targeting the Cotton Valley Taylor Sand (CVTS). By the end of the second quarter of 2010 we had drilled and completed four horizontal CVTS wells in East Texas. For the second quarter of 2010, net production from these four operated wells was approximately 6,139 Mcfe per day. We anticipate drilling four additional CVTS wells during the remainder of 2010.

A more complete overview and discussion of our operations can be found in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2009.

Overview of Second Quarter 2010 Results

Second Quarter 2010 financial and operating results include:

- We increased our oil and gas production volumes to 92,015 Mcfe per day, representing an increase of 12% from 82,074 Mcfe per day for the second quarter of 2009.

- We conducted drilling operations on 15 gross wells in the second quarter of 2010, 12 of which penetrated the Haynesville Shale. We added 8 gross (4 net) wells to production in the second quarter of 2010. At June 30, 2010, we had 11 gross (4 net) wells in the Haynesville Shale drilled but awaiting completion.

- We increased our net ownership in the Haynesville Shale play in Northwest Louisiana and East Texas to approximately 90,000 net acres at June 30, 2010.

- We drilled our first well on our Eagle Ford Shale acreage.

- We reduced our lease operating expense per Mcfe by 19% to $0.76 per Mcfe in the second quarter of 2010.

Results of Operations

For the three months ended June 30, 2010, we reported a net loss applicable to common stock of $23.1 million, or $0.64 per basic and diluted share, on total revenue of $34.2 million as compared to a net loss applicable to common stock of $36.5 million, or $1.02 per basic and diluted share, on total revenue of $26.3 million for the three months ended June 30, 2009. The rise in average oil and gas prices period to period contributed $4.1 million and the increase in production contributed $3.7 million to the $7.8 million increase in oil and gas revenues as compared to the three months ended June 30, 2009. We recorded a $0.3 million gain on derivatives not designated as hedges in the three months ended June 30, 2010 compared to a $2.6 million gain on derivatives not designated as hedges for the three months ended June 30, 2009. The decrease in the derivative gain between periods is due to the increase in oil and gas prices. We increased our valuation allowance in the three months ended June 30, 2010, resulting in our recording no income tax benefit for the period compared to a tax benefit of $21.5 million in the three months ended June 30, 2009.

For the six months ended June 30, 2010, we reported a net loss applicable to common stock of $20.3 million, or $0.57 per basic and diluted share, on total revenue of $74.6 million as compared to a net loss applicable to common stock of $34.9 million, or $0.97 per basic and diluted share, on total revenue of $54.7 million for the six months ended June 30, 2009. The rise in average oil and gas prices period to period increased oil and gas revenues by approximately $10.4 million and the production increase contributed approximately $9.4 million to the increase of $19.8 million in oil and gas revenues. Due to favorable terms on our hedges verses market prices, we recorded a $35.0 million gain on derivatives not designated as hedges in the six months ended June 30, 2010 compared to a $39.6 million gain on derivatives not designated as hedges for the six months ended June 30, 2009. We did not record any income tax benefit in the six months ended June 30, 2010 compared to an income tax benefit of $20.2 million for the six months ended June 30, 2009, as we increased our valuation allowance in the fourth quarter of 2009.

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Oil and Natural Gas Revenues

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

Summary Operating Information:

(In thousands, except for price data)	Three Months Ended June 30, 2010	2009	Variance		Six Months Ended June 30, 2010	2009	Variance	
Revenues:								
Natural gas	$ 31,772	$ 24,058	$ 7,714	32%	$ 69,690	$ 50,977	$ 18,713	37%
Oil and condensate	2,279	2,176	103	5%	4,787	3,697	1,090	29%
Natural gas, oil and condensate	34,051	26,234	7,817	30%	74,477	54,674	19,803	36%
Operating revenues	34,162	26,263	7,899	30%	74,617	54,724	19,893	36%
Operating expenses	46,939	80,210	(33,271)	(41%)	108,725	136,217	(27,492)	(20%)
Operating loss	(12,777)	(53,947)	41,170	(76%)	(34,108)	(81,493)	47,385	(58%)
Net loss applicable to common stock	(23,111)	(36,494)	13,383	(37%)	(20,292)	(34,862)	14,570	(42%)
Net Production:								
Natural gas (MMcf)	8,187	7,223	964	13%	15,967	13,768	2,199	16%
Oil and condensate (MBbls)	31	41	(10)	(24%)	64	86	(22)	(26%)
Total (Mmcfe)	8,373	7,469	904	12%	16,351	14,287	2,064	14%
Average daily production (Mcfe/d)	92,015	82,074	9,941	12%	90,340	78,931	11,409	14%
Average realized sales price per unit:								
Natural gas (per Mcf)	$ 3.88	$ 3.33	$ 0.55	17%	$ 4.36	$ 3.70	$ 0.66	18%
Oil and condensate (per Bbl)	73.21	52.98	20.23	38%	74.64	42.75	31.89	75%
Total (per Mcfe)	4.07	3.51	0.56	16%	4.55	3.83	0.72	19%

Revenues from operations increased 30% for the three months ended June 30, 2010 compared to the same period in 2009 resulting from a 16% increase in realized sales prices and a production increase of 12%. Revenues from operations increased 36% for the six months ended June 30, 2010 compared to the same period in 2009 as realized sales prices increased 19% and production increased 14%. The production increase in the three and six month periods ended June 30, 2010 over the same periods in 2009 are due to the increase in the production volumes obtained from our Haynesville shale wells. In the first half of 2010, 54 Haynesville wells were producing compared to 25 Haynesville wells in the first half of 2009.

For the three months ended June 30, 2010, our average realized price was $4.82 per Mcf including the effect of the realized gains and losses on our natural gas derivatives. Our average realized price was $3.88 per Mcf, excluding the effect of the realized gains and losses on our natural gas derivatives. For the three months ended June 30, 2009, our average realized price was $7.09 per Mcf including the effect of the realized gains and losses on our natural gas derivatives. Our average realized price was $3.33 per Mcf, excluding the effect of the realized gains and losses on our natural gas derivatives.

For the six months ended June 30, 2010, our average realized price was $4.95 per Mcf including the effect of the realized gains and losses on our natural gas derivatives. Our average realized price was $4.36 per Mcf, excluding the effect of the realized gains and losses on our natural gas derivatives. For the six months ended June 30, 2009, our average realized price was $7.21 per Mcf including the effect of the realized gains and losses on our natural gas derivatives. Our average realized price was $3.70 per Mcf, excluding the effect of the realized gains and losses on our natural gas derivatives.

The difference between our realized prices inclusive of the hedge realizations in the 2010 and 2009 periods relates to the floor price on our collars. In 2010, we had 50,000 MMBtu per day hedged at a floor price of $6.00 per MMBtu and in 2009, we had 60,000 MMBtu per day hedged at an average of $8.48 per MMbtu. Additionally we did not have any basis swap contract positions in 2009 where in 2010 we had realized losses on these contracts of $1.1 million and $2.3 million for the three and six months ended June 30, 2010, respectively.

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Operating Expenses

The following tables present our comparative operating expenses related to continuing operations:

Operating Expenses (in thousands)	Three Months Ended June 30, 2010	2009	Variance		Six Months Ended June 30, 2010	2009	Variance	
Lease operating expenses	$ 6,329	$ 6,984	$ (655)	(9%)	$ 13,561	$ 15,980	$ (2,419)	(15%)
Production and other taxes	390	1,049	(659)	(63%)	1,353	2,537	(1,184)	(47%)
Transportation	2,189	2,591	(402)	(16%)	4,642	5,179	(537)	(10%)
Depreciation, depletion and amortization	28,403	36,537	(8,134)	(22%)	58,616	70,195	(11,579)	(16%)
Exploration	2,627	2,959	(332)	(11%)	5,606	5,179	427	8%
Impairment		23,490	(23,490)	100%		23,490	(23,490)	(100%)
General and administrative	7,001	6,713	288	4%	16,447	13,770	2,677	19%
Gain on sale of assets		(113)	113	100%		(113)	113	100%
Other					8,500		8,500	100%

Operating Expenses per Mcfe	Three Months Ended June 30, 2010	2009	Variance		Six Months Ended June 30, 2010	2009	Variance	
Lease operating expenses	$ 0.76	$ 0.94	$ (0.18)	(19%)	$ 0.83	$ 1.12	$ (0.29)	(26%)
Production and other taxes	0.05	0.14	(0.09)	(64%)	0.08	0.18	(0.10)	(56%)
Transportation	0.26	0.35	(0.09)	(26%)	0.28	0.36	(0.08)	(22%)
Depreciation, depletion and amortization	3.39	4.89	(1.50)	(31%)	3.58	4.91	(1.33)	(27%)
Exploration	0.31	0.40	(0.09)	(23%)	0.34	0.36	(0.02)	(6%)
Impairment		3.14	(3.14)	100%		1.64	(1.64)	(100%)
General and administrative	0.84	0.90	(0.06)	(7%)	1.01	0.96	0.05	5%
Gain on sale of assets		(0.02)	0.02	100%		(0.01)	0.01	100%
Other					0.52		0.52	100%

Lease Operating. Lease operating expense (LOE) for the three months ended June 30, 2010 was $6.3 million, a decrease of $0.7 million, or 9%, from the $7.0 million for the three months ended June 30, 2009. The cost decrease is the result of lower saltwater disposal and compression costs and a greater percentage of our production volumes coming from the Haynesville Shale which has a much lower LOE per unit of production. We realized a $0.3 million savings from the continuing impact of the saltwater disposal systems installed in the second quarter of 2009. Compression costs decreased $0.4 million as we negotiated more favorable terms on certain rental contracts. On a per unit basis, LOE decreased 19% to $0.76 per Mcfe for the three months ended June 30, 2010 compared to the same period in 2009. The unit cost decrease is the result of cost reductions, a 12% increase in production volumes and an increasing portion of our production coming from the Haynesville Shale which carries lower production costs.

LOE for the six months ended June 30, 2010 was $13.6 million, a decrease of $2.4 million, or 15%, from the $16.0 million in the six months ended June 30, 2009. The cost decrease is the result of lower saltwater disposal cost as we realized $1.9 million in savings due to the continuing impact of the saltwater disposal systems installed in the second quarter of 2009. We also realized $1.1 million in compression cost savings as a result of more favorable rental contract rates. These cost savings were partially offset by increased workover costs of $0.6 million. On a per unit basis, LOE decreased 26% to $0.83 per Mcfe for the six months ended June 30, 2010 compared to the same period in 2009. This decrease is the result of the lower costs, the 14% increase in production volumes and an increasing portion of our production coming from the Haynesville Shale which carries lower production costs.

Production and Other Taxes. Production and other taxes for the three months ended June 30, 2010 was $0.4 million which includes ad valorem tax of $0.5 million reduced by a $0.1 million production tax credit. The production tax represents $0.6 million current period expense reduced by $0.7 million in high cost credits associated with the wells we have drilled horizontally in Louisiana. During the comparable period in 2009, production and other taxes were $1.0 million, which included ad valorem tax of $0.8 million and production tax of $0.2 million. Production tax in the three months ended June 30, 2009 included $0.5 million in Tight Gas Sands (TGS) tax credits.

Production and other taxes for the six months ended June 30, 2010 was $1.3 million which includes ad valorem tax of $0.9 million and production tax of $0.4 million. Production tax included $1.2 million of new TGS tax credits for our wells in the State of Texas and for our horizontally drilled wells in Louisiana. During the comparable period in 2009, production and other taxes were $2.5 million, which included ad valorem tax of $1.5 million and production tax of $1.0 million. Production tax in the six months ended June 30, 2009 included $1.0 million in TGS credits.

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TGS credits allow for reduced and/or the complete elimination of 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. We anticipate that we will incur a gradually lower production tax rate in the future as we add additional Texas wells to our production base and as reduced rates are approved.

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.

Transportation. Transportation expense in the three months ended June 30, 2010 was $2.2 million ($0.26 per Mcfe) compared to $2.6 million ($0.35 per Mcfe) for the three months ended June 30, 2009. Transportation expense for the six months ended June 30, 2010 was $4.6 million ($0.28 per Mcfe) compared to $5.2 million ($0.36 per Mcfe) in the six months ended June 30, 2009. The decrease in both the three and six months periods is a function of our changing geographic production mix, as well as a larger portion of sales coming from non-operated properties from which the operator nets the transportation cost from revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) for the three months ended June 30, 2010 decreased to $28.4 million from $36.5 million for the three months ended June 30, 2009 as a result of a lower DD&A rate. The average DD&A rate for the three months ended June 30, 2010 was $3.39 per Mcfe compared to $4.89 per Mcfe for the same period in 2009. DD&A for the six months ended June 30, 2010 decreased to $58.6 million from $70.2 million for the six months ended June 30, 2009 as a result of a lower DD&A rate. The average DD&A rate for the six months ended June 30, 2010 was $3.58 per Mcfe compared to $4.91 per Mcfe for the same period in 2009.

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

We calculated 2010 and 2009 DD&A rates using the December 31, 2009 and December 31, 2008 reserves, respectively. Proved developed reserves increased 9% from 152.5 Bcfe at December 31, 2008 to 165.5 Bcfe at December 31, 2009.

Exploration. Exploration expense for the three months ended June 30, 2010, decreased $0.3 million to $2.6 million compared to the same period in 2009. The second quarter of 2009 includes early termination fees of $1.1 million for two drilling rigs. The impact of this decrease in the current period is offset by $0.4 million in exploratory seismic costs for our 3-D seismic program in the Angelina River area and other exploration costs for this area.

Exploration expense for the six months ended June 30, 2010 increased $0.4 million to $5.6 million compared to the comparable 2009 period. The six months ended June 30, 2010 includes $1.0 million in seismic costs including exploratory seismic costs for our Angelina River area 3-D seismic program. The six months ended June 30, 2010 also includes slightly higher exploration labor costs and undeveloped leasehold cost amortization as compared to the comparable 2009 period. Offsetting these increases in the current year is the impact of $1.1 million in early termination fees for two drilling rig contracts in 2009.

Impairment. We recorded impairment expense of $23.5 million for the three and six months ended June 30, 2009, having written down the carrying values on the Caddo Pine Island field in the amount of $22.7 million and on the Brachfield field in the amount of $0.7 million. We had no impairment expense in the three and six months ended June 30, 2010.

General and Administrative. General and administrative (G&A) expense increased $0.3 million, or 4%, to $7.0 million in the three months ended June 30, 2010 compared to $6.7 million in the same period in 2009. The increase relates to slightly higher labor costs over the prior year period. G&A on a per unit basis decreased to $0.84 per Mcfe from $0.90 per Mcfe as a result of a 12% increase in our production volumes in the second quarter of 2010 as compared to the second quarter of 2009. Stock based compensation expense, which is a non-cash item, amounted to $1.5 million in the second quarter of 2010 compared to $1.6 million for the same period in 2009.

G&A expense increased $2.6 million, or 19%, to $16.4 million in the six months ended June 30, 2010 compared to $13.8 million in the same period in 2009. The six months ended June 30, 2010 included $0.9 million of compensation costs related to the resignation of an officer of the company. See Note 2 Resignation of Executive Officer to our consolidated financial statements in this report for more information. This amount includes non-cash charges of $0.3 million and $0.4 million for the accelerated vesting and modification of restricted stock and stock options, respectively. This charge also includes $0.2 million for a consulting agreement. G&A expense for six months ended June 30, 2010 also includes $0.9 million for 2009 bonuses paid out in March 2010. The remaining increase is related to generally higher compensation cost and stock based compensation. Stock based compensation expense, a non-cash item, amounted to $4.0 million for the six months ended June 30, 2010 compared to $3.2 million for the same period in 2009. G&A on a per unit basis increased to $1.01 per Mcfe compared to $0.96 per Mcfe for the same period in 2009 due to the $2.6 million overall increase offset by a 14% increase in production volumes in the first half of 2010 as compared to the first half of 2009.

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Other. Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC et al. On April 29, 2010 a state court in Caddo Parish, Louisiana, granted a judgment holding us solely responsible for the payment of $8.5 million in additional oil and gas lease bonus payments and related interest in an ongoing lawsuit involving the interpretation of a unique oil and gas lease provision. The lease provided for the payment of additional bonuses under certain circumstances in the event higher lease bonuses were paid by us, or our successors or assigns, within the surrounding area. Without our knowledge, one of the sub-lessees subject to the same lease paid substantially higher bonuses in the area. We believe that this ruling was improperly decided and, on July 8, 2010, filed a motion for suspensive appeal. We satisfied the requirements for posting a suspensive appeal bond by depositing $8.5 million with Iberia Bank in Shreveport, Louisiana for the account of the Clerk of Caddo Parish Court. We have accrued the full judgment amount, $8.5 million, as of June 30, 2010 which is reflected as Operating Expenses - other in the Consolidated Statement of Operations.

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 plan to record the effect of this agreement in the third quarter of 2010.

Other Income (Expense)

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2010	**2009**	**2010**	**2009**
Other income (expense):				
Interest expense	(9,195)	(5,298)	(18,315)	(10,506)
Interest income and other	53	202	106	448
Gain on derivatives not designated as hedges	320	2,556	35,049	39,562
Income tax benefit on continuing operations		21,505		20,151
Average funded borrowings	393,500	250,000	393,500	250,000
Average funded borrowings adjusted for debt discount	335,487	229,197	333,512	228,282
Weighted average interest rate	10.3%	9.3%	10.4%	9.3%

Interest Expense. Interest expense increased $3.9 million to $9.2 million in the three months ended June 30, 2010 compared to $5.3 million in the three months ended June 30, 2009 as a result of the higher average level of outstanding debt in the three months ended June 30, 2010. Interest expense increased $7.8 million to $18.3 million in the six months ended June 30, 2010 compared to $10.5 million in the six months ended June 30, 2009 as a result of the higher average level of outstanding debt in the six months ended June 30, 2010. The higher average level of debt in both the three and six month periods ended June 30, 2010 is the result of the issuance of our 5% convertible senior notes in September 2009.

Gain on Derivatives Not Designated as Hedges. Gain on derivatives not designated as hedges was $0.3 million for the three months ended June 30, 2010, including a realized gain of $7.7 million and an unrealized loss of $7.4 million for the change in fair value of our natural gas derivative contracts. The unrealized loss resulted from the roll off of settled contracts during the second quarter of 2010. As a comparison, gain on derivatives not designated as hedges for the three months ended June 30, 2009 was $2.6 million including a realized gain of $27.2 million and an unrealized loss of $24.4 million for the changes in fair value of our natural gas derivative contracts. The three months ended June 30, 2010 also included an immaterial income effect from our interest rate derivatives which matured in April 2010.

Gain on derivatives not designated as hedges was $35.0 million for the six months ended June 30, 2010, including a realized gain of $9.3 million and an unrealized gain of $25.8 million for the change in fair value of our natural gas derivative contracts. The unrealized gain was the result of the increase in the fair value of our derivative positions due to the decrease of natural gas futures prices from December 31, 2009. As a comparison, gain on derivatives not designated as hedges for the six months ended June 30, 2009 was $39.6 million including a realized gain of $48.3 million and an unrealized loss of $8.3 million for the changes in fair value of our natural gas derivative contracts. The six months ended June 30, 2010 also included an immaterial income effect from our interest rate derivatives which matured in April 2010.

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 six months ended June 30, 2010. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of June 30, 2010.

Income tax benefit for the three months ended June 30, 2009 was $21.5 million which includes a $1.7 million state income tax benefit. Income tax benefit for the six months ended June 30, 2009 was $20.2 million which includes a state income tax benefit of $1.9 million.

Liquidity and Capital Resources

Cash Flows

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

	Six months ended June 30,		
	2010	2009	Variance
Cash flow statement information:			
Net cash:			
Provided by operating activities	$ 47,653	$ 63,373	$ (15,720)
Used in investing activities	(112,391)	(180,045)	67,654
Used in financing activities	(3,906)	(5,508)	1,602
Decrease in cash and cash equivalents	$ (68,644)	$ (122,180)	$ 53,536

Operating activities. Net cash provided by operating activities decreased $15.7 million to $47.7 million for the six months ended June 30, 2010, from $63.4 million for the comparable 2009 period as less cash was realized from hedging settlements offset by increased production levels during the six month period.

Investing activities. Net cash used in investing activities was $112.4 million for the six months ended June 30, 2010, compared to $180.0 million for the six months ended June 30, 2009. We conducted drilling operations on 28 gross wells, 25 of which penetrated the Haynesville Shale during the first six months of 2010. In comparison, we conducted drilling operations on 36 gross wells, 22 of which penetrated the Haynesville Shale during the first six months of 2009.

Financing activities. Net cash used in financing activities was $3.9 million for the six months ended June 30, 2010, compared to $5.5 million for the same period in 2009. During this period we used cash on hand and cash flow to fund our operations. The cash used in financing activities for the periods consisted mainly of the payment of $3.0 million in preferred stock dividends.

For the year 2010, we have budgeted total capital expenditures of approximately $255 million. We expect to finance the remainder of our 2010 capital expenditures through a combination of cash flow from operations, cash on hand and availability under our senior credit facility.

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $350 million. The Senior Credit Facility matures on August 31, 2011. The Senior Credit Facility can be further extended to July 1, 2012 upon receipt of proceeds from a refinancing sufficient to prepay the 3.25% convertible senior notes due 2026. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of, the borrowing base. The initial borrowing base was established at $175 million. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50% or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations are made on a semi-annual basis on April 1 and October 1. In connection with the offering of our $218.5 million 5% convertible senior notes due 2029, we entered into an amendment of our Senior Credit Facility to permit the issues of the notes and required payments made on the notes thereafter and to exclude up to $175 million of our 3.25% convertible senior notes due 2026 or our 5% convertible senior notes due 2029 from the definition of Total Debt used in our financial covenants under the Senior Credit Facility. On April 20, 2010, the borrowing base was increased to $200 million. We currently have no amounts outstanding under the Senior Credit Facility. Any borrowed funds outstanding under the Senior Credit

Facility after August 31, 2010 will be classified as a current liability as long as the 3.25% senior convertible notes due 2026 are outstanding.

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

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

- Current Ratio of 1.0/1.0;
- Interest Coverage Ratio of not less than 3.0/1.0 for the trailing four quarters; and
- Total Debt no greater than 3.0 times EBITDAX for the trailing four quarters (EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Up to $175.0 million of our convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

We were in compliance with all the financial covenants of the Senior Credit Facility as of June 30, 2010.

3.25% Convertible Senior Notes Due 2026

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

Before December 1, 2011, we may not redeem the 2026 Notes. On or after December 1, 2011, we may redeem all or a portion of the 2026 Notes for cash, and the investors may require us to repurchase the 2026 Notes on each of December 1, 2011, 2016 and 2021. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem the 2026 Notes in cash or in certain circumstances redeem in a combination of cash and shares. The 2026 Notes are convertible into shares of our common stock at a rate equal to the sum of:

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

b) an additional amount of shares per $1,000 of principal amount of the 2026 Notes equal to the incremental share factor (2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price.

We separately account for the liability and equity components of the 2026 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. As of June 30, 2010, the 2026 Notes were carried on the balance sheet at $163.1 million with a debt discount balance of $11.9 million. As of December 31, 2009, the 2026 Notes were carried on the balance sheet at $159.1 million with a debt discount of $15.9 million. The remaining amount of debt discount as of June 30, 2010 will be amortized using the effective interest rate method based upon an original five year term through December 1, 2011.

Interest expense relating to the contractual interest rate and amortization of both financing cost and debt discount relating to the 2026 Notes for the three and six months ended June 30, 2010 was $3.6 million and $7.3 million, respectively. The effective interest rate on the liability component of the 2026 Notes was 9.0% and 9.1% for the three and six month periods ended June 30, 2010, respectively.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes (the 2029 Notes) due in October 2029. The 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.

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 the 2029 Notes in cash or in certain circumstances redeem in a combination of cash and shares. 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 the 2029 Notes (equal to an initial conversion price of approximately $34.66 per share of common stock).

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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 June 30, 2010, the $218.5 million 2029 Notes were carried on the balance sheet at $175.0 million with a debt discount balance of $43.5 million. As of December 31, 2009, the $218.5 million 2029 Notes were carried on the balance sheet at $171.1 million with a debt discount of $47.4 million. The debt discount will be amortized using the effective interest rate method based upon an original five year term through October 1, 2014. Interest expense recognized relating to the contractual interest rate and amortization of both financing cost and debt discount for the three and six months ended June 30, 2010 was $5.0 million and $9.9 million, respectively. The effective interest rate on the liability component of the 2029 Notes was 11.4% and 11.6% for the three and six month periods ended June 30, 2010, respectively.

Capped Call Option Transactions

On December 10, 2007, we closed the public offering of 6,430,750 shares of our common stock at a price of $23.50 per share. Net proceeds from the offering were approximately $145.4 million after deducting the underwriters discount and estimated offering expenses. We used approximately $123.8 million of the net proceeds to pay off outstanding borrowings under our Senior Credit Facility, and approximately $21.6 million of the net proceeds to purchase capped call options on shares of our common stock from affiliates of Bear Stearns and Company (BSC) and J.P. Morgan Securities Inc. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. Approximately 77,333 options per trading day expired over each of three separate 25 consecutive trading day settlement periods. During 2009, two-thirds of the options expired. The remaining one-third of the options subject to the capped call expired unexercised in the second quarter of 2010. For more information on these transactions, please see our Annual Report on Form 10-K for the year ended December 31, 2009.

Accounting Pronouncements

See Note 1 Description of Business and Significant Accounting Policies New Accounting Pronouncements to our consolidated financial statements included in Part I Item 1 of this Form 10-Q for a discussion of recently issued pronouncements.

In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. These revised disclosures are required, with certain exceptions, for interim and annual reporting periods effective January 1, 2010. For information concerning the fair value at June 30, 2010 of our derivative financial instruments and our long-term debt financial instruments, see Note 9 Fair Value of Financial Instruments to our consolidated financial statements in this report.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements which have been 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 our 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, 2009, includes a discussion of our critical accounting policies and there have been no material changes to such policies.

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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 June 30, 2010, 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; and

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

Our hedging contracts fall within our targeted range of 30% to 70% of our estimated net oil and gas production volumes for the applicable periods of 2010. The fair value of the natural gas hedging contracts in place at June 30, 2010, resulted in a net current asset of $30.9 million. Based on oil and gas pricing in effect at June 30, 2010, a hypothetical 10% increase in oil and gas prices would have resulted in a derivative asset of $15.3 million, while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $50.4 million. See Note 8 Derivative Activities to our consolidated financial statements in this report for additional information.

As of June 30, 2010, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, J.P. Morgan or Bank of Montreal, were as follows:

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Average Floor/ Cap**			**Fair Value at June 30, 2010 (in thousands)**
Natural gas (MMBtu)						$ 32,107
3Q 2010	50,000	4,600,000	$	6.00	$7.10	
4Q 2010	50,000	4,600,000	$	6.00	$7.10	
1Q 2011	40,000	3,600,000	$	6.00	$7.09	
2Q 2011	40,000	3,640,000	$	6.00	$7.09	
3Q 2011	40,000	3,680,000	$	6.00	$7.09	
4Q 2011	40,000	3,680,000	$	6.00	$7.09	
1Q 2012	40,000	3,640,000	$	6.00	$7.09	
2Q 2012	40,000	3,640,000	$	6.00	$7.09	
3Q 2012	40,000	3,680,000	$	6.00	$7.09	
4Q 2012	40,000	3,680,000	$	6.00	$7.09	
Basis Swaps (NYMEX/TexOk)			**Average Price (1)**			
Natural gas (MMBtu)						$ (1,240)
3Q 2010	50,000	4,600,000	$	0.368		
4Q 2010	50,000	4,600,000	$	0.368		
					Total	$ 30,867

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

The following table summarizes the realized and unrealized gains and losses we recognized on our natural gas derivatives for the three and six month periods ended June 30, 2010 and 2009.

	Three Months Ended June 30.		Six Months Ended June 30.	
Natural Gas Derivatives (in thousands):	**2010**	**2009**	**2010**	**2009**
Realized gain on natural gas derivatives	$ 7,686	$ 27,189	$ 9,329	$ 48,324
Unrealized gain (loss) on natural gas derivatives	(7,364)	(24,380)	25,742	(8,370)
Total gain on natural gas derivatives	$ 322	$ 2,809	$ 35,071	$ 39,954

Interest Rate Swap

We have no interest rate derivative position as of June 30, 2010, since all our contracts matured in April, 2010.

For the three months ended June 30, 2010, we recognized a loss of less than $0.1 million, including a realized loss of $0.5 million partially offset by an unrealized gain of $0.5 million. For the six months ended June 30, 2010, we recognized a loss of less than $0.1 million, including a realized loss of $1.1 million offset by an unrealized gain of $1.1 million.

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 Part II, Item 1A. Risk Factors of this Form 10-Q.

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.

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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 June 30, 2010, 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.

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 10 - Commitments and Contingencies to our consolidated financial statements in this Form 10-Q.

Item 1A Risk Factors

Except as disclosed below, 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, 2009.

Future results from our impending commencement of initial drilling operations in the Eagle Ford Shale, an emerging play in South Texas with limited drilling and production history, are subject to more uncertainties than our drilling operations in more established formations and may not meet our expectations for reserves or production or may be subject to delays.

We have only recently committed to commence drilling operations in the Eagle Ford Shale in South Texas. Production history from horizontal wells in the Eagle Ford Shale is limited. In addition, we will be competing with more established operators in the area for drilling rigs and equipment and fracturing and pressure pumping crews. The ultimate success of our drilling and completion strategy and techniques in this formation and the time required to achieve such success is accordingly subject to more uncertainties than in areas where we have more established production and operating histories.

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

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission (the SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Item 6 Exhibits

*10.1	Participation Agreement between the Company and Turnham Interests, Inc. dated May 25, 2010.
*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.
*101.CAL	XBRL Calculation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document
*101.INS	XBRL Instance Document
*101.LAB	XBRL Labels Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.SCH	XBRL Schema 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: August 5, 2010	By:	/s/ WALTER G. GOODRICH **Walter G. Goodrich** **Vice Chairman & Chief Executive Officer**
Date: August 5, 2010	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 JUNE 30, 2010

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