GOODRICH PETROLEUM CORP
Form 10-Q
August 06, 2009
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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, 2009

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

808 Travis, Suite 1320

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 ¨ 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 3, 2009 was 37,395,224.

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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, Except Share Amounts)

(Unaudited)

	June 30, 2009	December 31, 2008 (as adjusted)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 25,368	$ 147,548
Accounts receivable, trade and other, net of allowance	6,551	7,019
Accrued oil and gas revenue	12,895	15,595
Fair value of oil and gas derivatives	46,740	55,276
Assets held for sale	13	13
Prepaid expenses and other	3,714	2,778
Total current assets	95,281	228,229
PROPERTY AND EQUIPMENT:		
Oil and gas properties (successful efforts method)	1,259,618	1,107,400
Furniture, fixtures and equipment	3,547	3,171
	1,263,165	1,110,571
Less: Accumulated depletion, depreciation and amortization	(400,251)	(304,236)
Net property and equipment	862,914	806,335
Fair value of oil and gas derivatives	166	
Deferred tax assets	1,640	
Deferred financing cost	4,665	3,723
TOTAL ASSETS	$ 964,666	$ 1,038,287
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 42,413	$ 41,462
Accrued liabilities	25,684	52,928
Deferred tax liabilities	16,359	18,931
Income taxes payable	44	1,383
Fair value of interest rate derivatives	1,699	1,187
Accrued abandonment costs	2,729	2,554
Total current liabilities	88,928	118,445
LONG-TERM DEBT	230,404	226,723
Accrued abandonment costs	11,898	11,250
Deferred tax liabilities		15,904

Fair value of interest rate derivatives		617
Total liabilities	331,230	372,939
Commitments and contingencies (See Note 12)		
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 37,394,084 and 37,562,569 shares, respectively	7,154	7,188
Treasury stock (458 and 9,793 shares, respectively)	(12)	(293)
Additional paid in capital	602,456	599,753
Retained earnings	21,588	56,450
Total stockholders equity	633,436	665,348
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 964,666	$ 1,038,287

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, 2009	Three Months Ended June 30, 2008 (as adjusted)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (as adjusted)
REVENUES:				
Oil and gas revenues	$ 26,234	$ 64,852	$ 54,674	$ 111,049
Other	29	321	50	477
	26,263	65,173	54,724	111,526
OPERATING EXPENSES:				
Lease operating expense	6,984	7,669	15,980	14,766
Production and other taxes	1,049	2,334	2,537	3,589
Transportation	2,591	2,386	5,179	4,256
Depreciation, depletion and amortization	36,537	29,033	70,195	54,118
Exploration	2,959	1,776	5,179	3,779
Impairment of oil and gas properties	23,490		23,490	
General and administrative	6,713	5,920	13,770	11,360
Gain on sale of assets	(113)		(113)	
	80,210	49,118	136,217	91,868
Operating income (loss)	(53,947)	16,055	(81,493)	19,658
OTHER INCOME (EXPENSE):				
Interest expense	(5,298)	(6,026)	(10,506)	(11,447)
Interest income	144		383	
Gain (loss) on derivatives not designated as hedges	2,556	(48,947)	39,562	(73,434)
	(2,598)	(54,973)	29,439	(84,881)
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(56,545)	(38,918)	(52,054)	(65,223)
INCOME TAX BENEFIT	21,505		20,151	
LOSS FROM CONTINUING OPERATIONS	(35,040)	(38,918)	(31,903)	(65,223)
DISCONTINUED OPERATIONS (SEE NOTE 11):				
Gain (loss) on sale of assets, net of tax		(120)		280
Income (loss) from discontinued operations, net of tax	58	(101)	65	284
	58	(221)	65	564
NET LOSS	(34,982)	(39,139)	(31,838)	(64,659)
Preferred stock dividends	1,512	1,511	3,024	3,023
NET LOSS APPLICABLE TO COMMON STOCK	$ (36,494)	$ (40,650)	$ (34,862)	$ (67,682)

Net loss per common share - basic:								
Loss from continuing operations	$	(1.02)	$	(1.26)	$	(0.97)	$	(2.14)
Discontinued operations	$		$	(0.01)	$		$	0.02
Net loss applicable to common stock	$	(1.02)	$	(1.27)	$	(0.97)	$	(2.12)
Net loss per common share - diluted:								
Loss from continuing operations	$	(1.02)	$	(1.26)	$	(0.97)	$	(2.14)
Discontinued operations	$		$	(0.01)	$		$	0.02
Net loss applicable to common stock	$	(1.02)	$	(1.27)	$	(0.97)	$	(2.12)
Weighted average common shares outstanding - basic		35,937		32,124		35,953		31,915
Weighted average common shares outstanding - diluted		35,937		32,124		35,953		31,915

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, 2009	Six Months Ended June 30, 2008 (as adjusted)
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (31,838)	$ (64,659)
Adjustments to reconcile net loss to net cash provided by operating activities-		
Depletion, depreciation and amortization	70,195	54,118
Unrealized loss on derivatives not designated as hedges	8,265	71,852
Deferred income taxes	(20,116)	
Dry hole costs	101	
Amortization of leasehold costs	2,901	2,449
Impairment of oil and gas properties	23,490	
Stock based compensation (non-cash)	3,203	2,654
Gain on sale of assets	(113)	(280)
Amortization of debt discount and finance cost	4,621	4,230
Other non-cash		53
Change in assets and liabilities:		
Accounts receivable trade and other, net of allowance	468	1,455
Deferred revenue		(12,500)
Accrued oil and gas revenue	2,700	(14,715)
Prepaid expense and other	(1,926)	484
Accounts payable	951	9,806
Accrued liabilities	471	2,149
Net cash provided by operating activities	63,373	57,096
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(180,193)	(175,620)
Asset sale deposit		8,927
Proceeds from sale of assets	148	280
Net cash used in investing activities	(180,045)	(166,413)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments of bank borrowings		(72,500)
Proceeds from bank borrowings		188,000
Exercise of stock options and warrants		81
Deferred financing cost	(1,802)	(1,492)
Preferred stock dividends	(3,024)	(3,023)
Other	(682)	(215)
Net cash provided by (used in) financing activities	(5,508)	110,851

Increase (decrease) in cash and cash equivalents	(122,180)	1,534
Cash and cash equivalents, beginning of period	147,548	4,448
Cash and cash equivalents, end of period	$ 25,368	$ 5,982

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

The consolidated financial statements of Goodrich Petroleum Corporation (Goodrich or the Company or we) 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 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, 2008. The results of operations for the three and six months ended June 30, 2009, are not necessarily indicative of the results to be expected for the full year.

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 accounting principles generally accepted in the United States. Actual results could differ from those estimates.

Impairment Proved oil and gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying amounts may not be recoverable. In performing this review, future net cash flows are calculated based on estimated future oil and gas revenues less future expenditures necessary to develop and produce the reserves. If the sum of these estimated future cash flows (undiscounted) is less than the carrying amount of the property, an impairment loss is recognized for the excess of the property s carrying amount over its estimated fair value based on estimated discounted future cash flows. We perform this comparison using our estimates of future commodity prices and proved and probable reserves. As a result of the disappointing drilling results related to the Caddo Pine Island field and the lower natural gas price environment as of June 30, 2009, we wrote down the carrying value of properties with an aggregate net book value of $25.1 million to their aggregate fair value of $1.6 million resulting in the recognition of a $23.5 million impairment in the second quarter of 2009. The company has determined that this valuation is classified within level three of the valuation hierarchy

Assets Held for Sale Assets Held for Sale as of June 30, 2009, represent our remaining assets in Plumb Bob field located in South Louisiana.

Income Taxes We follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*, (SFAS 109) as clarified by Financial Accounting Standards Board (FASB) Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), which requires income taxes be accounted for 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.

New Accounting Pronouncements

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, an amendment of FASB Statement No. 133 (SFAS 161). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133 by requiring enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 is effective as of January 1, 2009. As SFAS 161 provides only disclosure requirements, the adoption of this standard does not have an impact on our results of operations, cash flows or financial positions. See Note 8.

On May 9, 2008, the FASB issued FASB Staff Position (FSP) Accounting Principles Board (APB) 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlements)* (FSP APB 14-1). FSP APB 14-1 requires the issuer of certain convertible debt instruments that may be settled in cash on conversion to separately account for the liability and equity components in a manner that reflects the issuer s nonconvertible debt borrowing rate. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of FSP APB 14-1 is for financial statements issued for fiscal years beginning after December 15, 2008. FSP APB 14-1 did not permit earlier adoption, however it does require retrospective application to all periods presented in the financial statements (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). Our $175 million 3.25% convertible senior notes due 2026 (see Note 4) are affected by this new standard. Accordingly, we adopted the standard as of January 1, 2009. The retrospective application of this pronouncement affects years 2006 through 2008. See Note 2 for the retrospective adjustment to comparable financial statements.

In December 2008, the SEC issued a final rule adopting revisions to its oil and gas reporting disclosures. The revisions are intended to provide investors with more meaningful and comprehensive information related to the determination and disclosure of oil and gas reserves information. The provisions of this final rule are effective for fiscal years ending on or after December 31, 2009. We are currently assessing the impact that this final rule will have on our financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, which was effective beginning with our second quarter financial reporting. The FSP amends FAS 107, *Disclosures about Fair Value of Financial Instruments*, and Accounting Principles Board Opinion 28, *Interim Financial Reporting*, to require disclosures about fair value of financial instruments for interim financial statements of publicly traded companies. The adoption of the FSP did not have a material impact on our results of operations, financial position, or cash flows. See Note 10 for the related disclosures.

In May 2009, the FASB issued FAS 165, *Subsequent Events*, which establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before the financial statements are issued. This new standard was effective beginning with our second quarter financial reporting. The company has evaluated subsequent events through August 6, 2009, the date of issuance of the financial statements. The adoption of this standard did not have a material impact on our results of operations, financial position, or cash flows.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and Hierarchy of Generally Accepted Accounting Principles (GAAP), a replacement of FASB Statement No. 162 (SFAS 168) which establishes the Accounting Standards Codification (the Codification) and SEC interpretive releases as the sources for authoritative GAAP. The Codification will supersede all existing non-SEC accounting and reporting standards under GAAP effective for our Form 10-Q for the quarterly period ended September 30, 2009. The Codification is not intended to change existing GAAP. Accordingly, we do not anticipate a material impact on our consolidated financial statements.

On June 18, 2009 the Emerging Issues Task Force (EITF) reached consensus on Issue No. 09-1, Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance (EITF 09-1). EITF 09-1 requires that, at the date of issuance, a share-lending arrangement entered into on an entity s own shares in contemplation of a convertible debt offering or other financing is required to be measured at fair value and accounted for as an issuance cost in the financial statements of the entity. It also clarifies the treatment of the loaned shares in the computation of basic and diluted earnings per share, requires additional disclosures in the financial statements with respect to share lending arrangements and requires recognition of a loss in the event that it becomes probable that the counterparty will default. The issue is effective for fiscal years beginning on or after December 15, 2009 and interim periods within those fiscal years for arrangements outstanding at the beginning of those years. The issue requires retrospective application for all arrangements outstanding as of the beginning of the fiscal years beginning on or after December 15, 2009. We are currently evaluating the impact of the provision on our financial statements as it relates to the shares outstanding under the share lending agreement that we entered into in connection with the issuance of our 3.25% Convertible Senior Notes in December 2006.

We do not believe that any other recently issued, but not yet effective accounting pronouncements, if adopted, would have a material effect on our accompanying financial statements.

NOTE 2 Retrospective Adjustment of Prior Period Financial Statements

We adopted FSP APB 14-1 on January 1, 2009**.** FSP APB 14-1 did not allow early adoption but does require that previously issued financial statements for comparability purposes be retrospectively adjusted for affect of the standard. The following tables reflect the retrospective application to the line items affected on previously issued financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

FSP APB 14-1 Adoption Retrospective Adjustments

(In Thousands)

Financial Statement Line Items Adjusted

Balance Sheet

	As of December 31, 2008			
	As Reported	Equity/ Debt Discount	Finance Cost Adjustment	As Adjusted
Deferred financing cost	$ 4,382	$	$ (659)	$ 3,723
Total Assets	$ 1,038,946	$	$ (659)	$ 1,038,287
Long-term debt	$ 250,000	$ (23,277)	$	$ 226,723
Deferred income tax liabilities	7,988	8,147	(231)	15,904
Total liabilities	388,300	(15,130)	(231)	372,939
Additional paid in capital	576,961	23,920	(1,128)	599,753
Retained earnings	64,540	(8,790)	700	56,450
Total stockholders equity	650,646	15,130	(428)	665,348
Total Liabilities and Stockholders Equity	$ 1,038,946	$	$ (659)	$ 1,038,287

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income Statement

	Three Months Ended June 30, 2008			
	As Reported	Debt Discount	Loan Cost Adjustment	As Adjusted
Interest Expense	$ (4,390)	$ (1,693)	$ 57	$ (6,026)
Income (loss) from continuing operations before income taxes	(37,282)	(1,693)	57	(38,918)
Income (loss) from continuing operations	(37,282)	(1,693)	57	(38,918)
Net income (loss)	(37,503)	(1,693)	57	(39,139)
Net income (loss) applicable to common stock	(39,014)	(1,693)	57	(40,650)
Net loss per Common Share - Basic				
Loss from continuing operations	$ (1.16)			$ (1.26)
Net loss applicable to common stock	$ (1.21)			$ (1.27)
Net loss per Common Share - Diluted				
Loss from continuing operations	$ (1.16)			$ (1.26)
Net loss applicable to common stock	$ (1.21)			$ (1.27)

Income Statement

	Six Months Ended June 30, 2008			
	As Reported	Debt Discount	Loan Cost Adjustment	As Adjusted
Interest Expense	$ (8,173)	$ (3,387)	$ 113	$ (11,447)
Income (loss) from continuing operations before income taxes	(61,949)	(3,387)	113	(65,223)
Income (loss) from continuing operations	(61,949)	(3,387)	113	(65,223)
Net income (loss)	(61,385)	(3,387)	113	(64,659)
Net income (loss) applicable to common stock	(64,408)	(3,387)	113	(67,682)
Net loss per Common Share - Basic				
Loss from continuing operations	$ (1.94)			$ (2.14)
Net loss applicable to common stock	$ (2.02)			$ (2.12)
Net loss per Common Share - Diluted				
Loss from continuing operations	$ (1.94)			$ (2.14)
Net loss applicable to common stock	$ (2.02)			$ (2.12)

NOTE 3 Asset Retirement Obligations

We apply SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143) which requires us to record the fair value of a liability associated with the retirement obligations of our tangible long-lived assets in the periods in which it is incurred. We capitalize the discounted fair value of the liability when initially incurred. The liability is accreted through accretion expense to its full fair value over the life of the long-lived asset. Accretion expense is included in depreciation, depletion and amortization on our consolidated statement of operations.

The reconciliation of the beginning and ending asset retirement obligation for the six months ended June 30, 2009, is as follows (in thousands):

Beginning balance, January 1, 2009	$ 13,804
Liabilities incurred	376
Liabilities settled or sold	(4)
Accretion expense (reflected in depletion, depreciation and amortization expense)	451

Ending balance, June 30, 2009	14,627
Less current portion	2,729
	$ 11,898

The ending balance at June 30, 2009, includes $1.4 million related to Assets Held for Sale. See Note 11.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 4 Long-Term Debt

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

	June 30, 2009	December 31, 2008 (as adjusted)
Senior Credit Facility	$	$
Second Lien Term Loan	75,000	75,000
3.25% convertible senior notes due 2026	175,000	175,000
Debt discount on convertible senior notes	(19,596)	(23,277)
Total long-term debt	$ 230,404	$ 226,723

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $350 million. The Senior Credit Facility matures on October 1, 2010 and under certain conditions related to our refinancing of the Second Lien Term Loan the maturity can be extended to 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 convertible senior notes. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of the borrowing base. The initial borrowing base was established at $175 million. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50%, or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on each April 1 and October 1 beginning on October 1, 2009. The current availability under the credit facility is $175 million.

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

The terms of the Senior Credit Facility requires 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. The 3.25% convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

Second Lien Term Loan

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, secured, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. We had no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the Second Lien Term Loan accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. As of June 30, 2009, we were in compliance with all of the financial covenants of our Second Lien Term Loan. The terms of the Second Lien Term Loan Agreement contain financial covenants which include:

- an asset coverage ratio (defined as the present value of proved reserves discounted 10% to total debt, which excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0;

- a total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt excludes the 3.25% convertible senior notes); and

- an EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

Convertible Senior Notes

In December 2006, we sold $175 million of 3.25% convertible senior notes due in December 2026. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes are our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually, and interest is paid semi-annually on June 1 and December 1. Interest payments on the notes began on June 1, 2007.

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

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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

We adopted FSP APB 14-1 on January 1, 2009. FSP APB 14-1 requires that we separately account for the liability and equity components of our convertible senior notes in a manner that will reflect our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. On January 1, 2009, we recorded a beginning of period debt discount balance of $23.3 million which represents the unamortized debt discount of the original retrospective debt discount of approximately $37.0 million and an equity component net of tax of $23.9 million. As of June 30, 2009 the $175.0 million notes were carried on the balance sheet as $155.4 million with a debt discount balance of $19.6 million. This remaining amount of debt discount will be amortized using the effective interest rate method based upon an original 5 year term through December 1, 2011. Amortization of debt discount for the three and six months ended June 30, 2009 was $1.9 million and $3.7 million, respectively.

NOTE 5 Net Loss Per Common Share

Net loss applicable to common stock was used as the numerator in computing basic and diluted loss per common share for the three and six months ended June 30, 2009 and 2008. The following table reconciles the weighted average shares outstanding used for these computations (in thousands):

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008 (as adjusted)	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (as adjusted)
	(Amounts in thousands, except per share data)			
Basic loss per share:				
Loss applicable to common stock	$ (36,494)	$ (40,650)	$ (34,862)	$ (67,682)
Average shares of common stock outstanding (1)	35,937	32,124	35,953	31,915
Basic loss per share	$ (1.02)	$ (1.27)	$ (0.97)	$ (2.12)
Diluted loss per share:				
Loss applicable to common stock	$ (36,494)	$ (40,650)	$ (34,862)	$ (67,682)
Dividends on convertible preferred stock (2)				
Interest and amortization of loan cost on senior convertible notes, net of tax (3)	$	$	$	$
Diluted loss	$ (36,494)	$ (40,650)	$ (34,862)	$ (67,682)
Average shares of common stock outstanding (1)	35,937	32,124	35,953	31,915
Assumed conversion of convertible preferred stock (2)				
Assumed conversion of convertible senior notes (3)				
Stock options, warrants and restricted stock (4)				
Average diluted shares outstanding	35,937	32,124	35,953	31,915
Diluted loss per share	$ (1.02)	$ (1.27)	$ (0.97)	$ (2.12)

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

(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 have not been dilutive.

(3) Common shares issuable upon assumed conversion of our convertible senior notes amounting to 2,653,927 shares and the accrued interest on the senior notes were not included in the computation of diluted loss per share for the periods presented as they would have not 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, 2008 in the amounts of 590,845 and 428,676 shares, respectively, were not included in the computation of diluted loss per common share since their inclusion would have not been dilutive. Common shares issuable on assumed

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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 have not been dilutive.

NOTE 6 Income Taxes

We recorded tax benefits on continuing operations of $21.5 million for the three months ended June 30, 2009 resulting in an effective tax rate of 38.0%. For the six months ended June 30, 2009, we recorded tax benefits on continuing operations of $20.2 million resulting in an effective tax rate of 38.7%. The effective tax rates differ from the 35% federal statutory rate primarily due to state taxes including the benefit for Louisiana net operating losses generated which are available for carryback to 2008.

As of June 30, 2009, we had no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2008. 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, 2010.

NOTE 7 Stockholders Equity

Restricted Stock

During the six months ended June 30, 2009, we granted 12,975 shares of restricted stock with a weighted average value of $24.72 per share. During the same period, 83,479 restricted shares vested which had a weighted average grant date value of $22.39 per share.

Capped Call Option Transactions

On December 10, 2007, using the proceeds of a public offering, we purchased capped call options on our shares of common stock. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. Approximately 77,333 options per trading day will expire over each of three separate 25 consecutive trading day settlement periods, the first of which began on May 18, 2009, and again beginning on November 16, 2009 and May 18, 2010, respectively.

On the 25 consecutive trading days from May 18, 2009 through June 22, 2009, the first of the three tranches of options expired. During this period, the price of our common stock closed above the lower call strike price on all trading days resulting in our recoupment of 246,134 shares of our common stock. The shares recouped reduced our common stock outstanding, with no material affect on stockholders equity.

Adoption of FSP APB 14-1 Convertible Debt Instruments That May Be Settled in Cash Upon Conversion APIC

FSP APB 14-1 requires the issuer of certain convertible debt instruments that may be settled in cash on conversion to separately account for the liability and equity components in a manner that reflects the issuer s nonconvertible debt borrowing rate. As a result of the adoption of the standard, additional paid in capital was increased by $22.8 million, to reflect the deemed equity portion of the convertible notes. We also recorded a beginning of period adjustment to retained earnings of $8.1 million, representing the cumulative effect on retained earnings of the retrospective application of FSP APB 14-1 relating to after tax interest expense.

NOTE 8 Derivative Activities

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

Commodity Derivative Activity

We produce and sell oil and natural gas into a market where selling prices are historically volatile. For example, in the year 2008, Henry Hub natural gas spot price reached a high of $13.31 per MMBtu but at the end of July 2009 the price was down to $3.49 per MMBtu. We enter into swap contracts, costless collars or other derivative agreements from time to time to manage this commodity price risk for a portion of our production. Our strategy, which is administered by the Hedging Committee of our Board of Directors, and reviewed periodically by the entire Board of Directors, has been to generally hedge between 30% and 70% of our estimated total production for the period the derivatives are in effect. As of June 30, 2009, the commodity derivatives we used were in the form of:

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

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

(c) 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.

As of June 30, 2009, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, JP Morgan or Bank of Montreal, were as follows:

Collars (NYMEX)	**Daily Volume**	**Total Volume**	**Floor/Cap Average Price**	**Fair Value at June 30, 2009**
Natural gas (MMBtu)				$ 16,846,171
3Q 2009	20,000	1,840,000	$8.75 -$13.10	
4Q 2009	20,000	1,840,000	$8.75 -$13.10	
1Q 2010	10,000	900,000	$6.00 - $ 7.15	
2Q 2010	10,000	910,000	$6.00 - $ 7.15	
3Q 2010	10,000	920,000	$6.00 - $ 7.15	
4Q 2010	10,000	920,000	$6.00 - $ 7.15	
Swaps (NYMEX)			**Average Price**	
Natural gas (MMBtu)				16,313,437
3Q 2009	20,000	1,840,000	$8.83	
4Q 2009	20,000	1,840,000	$8.83	
Swaps (TexOk)			**Field Price (1)**	
Natural gas (MMBtu)				14,476,063
3Q 2009	20,000	1,840,000	$7.87	
4Q 2009	20,000	1,840,000	$7.87	
Basis Swaps (NYMEX/TexOk)			**Average Price (2)**	
Natural gas (MMBtu)				(729,838)
3Q 2009	40,000	3,680,000	$0.520	
4Q 2009	40,000	3,680,000	$0.520	
1Q 2010	50,000	4,500,000	$0.368	
2Q 2010	50,000	4,550,000	$0.368	
3Q 2010	50,000	4,600,000	$0.368	
4Q 2010	50,000	4,600,000	$0.368	
			Total	$ 46,905,833

(1) The index price is based upon Natural Gas Pipeline of America, TexOk zone as published in the Inside FERC. The comparable index price based on NYMEX was approximately $8.25/MMbtu.

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

The fair value of the oil and gas commodity contracts in place at June 30, 2009, that are marked to market resulted in a net current asset of $46.7 million and a net non-current asset of $0.2 million. We measure the fair value of our commodity derivatives contracts by applying the income approach and these contracts are classified within level two of the valuation hierarchy. See Note 9. For the three months ended June 30, 2009, we recognized in earnings a $2.8 million gain from these instruments, which consisted of $27.2 million in realized gains offset by $24.4 million in unrealized losses. For the six months ended June 30, 2009, we recognized in earnings a $40.0 million gain from these instruments, which consisted of $48.3 million in realized gains offset by $8.3 million in unrealized losses.

During the second quarter of 2009, we entered into basis swap contracts totaling 50,000 MMbtu/day and a 10,000 MMbtu/day NYMEX collar contract with a floor and ceiling price of $6.00 and $7.15 per MMbtu, respectively. These contracts were for the calendar year 2010, as detailed above.

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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.

Interest Rate Swaps

We have variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. We have not designated these swaps as a hedge. At June 30, 2009, we had the following interest rate swaps in place with BNP Paribas and Bank of Montreal:

Effective Date	Maturity Date	LIBOR Swap Rate	Notional Amount (Millions)	Fair Value (Dollars)
4/22/2008	4/22/2010	3.19%	$ 25.0	$ (566,554)
4/22/2008	4/22/2010	3.19%	50.0	(1,132,353)
				$ (1,698,907)

The fair value of the interest rate swap contract at June 30, 2009, resulted in a liability of $1.7 million which is reflected on the balance sheet as a current liability. We measure the fair value of our interest rate swaps by applying the income approach and these contracts are classified within level two of the valuation hierarchy. See Note 9. For the three and six months ended June 30, 2009, we recognized losses of $0.2 million and $0.4 million, respectively, from interest rate swaps.

NOTE 9 Fair Value Measurements

We adopted SFAS No. 157, *Fair Value Measurements* (SFAS 157), effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS 157 to January 1, 2009 for nonfinancial assets and liabilities. Fair value, as defined in SFAS 157, is 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. As of January 1, 2009, SFAS 157 affects the Company in the fair value measurement of the commodity and interest rate derivative positions for financial assets/liabilities and the Company s Asset Retirement Obligation nonfinancial liabilities which must be classified in one of the following categories:

Level 1 Inputs

These inputs come from quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 Inputs

These inputs are other than quoted prices that are observable, for an asset or liability. This includes: quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability; and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 Inputs

These are unobservable inputs for the asset or liability which require the Company s own assumptions.

As required by SFAS 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of our investments and financial instruments by SFAS 157 pricing levels as of June 30, 2009:

	Fair Value Measurement (in thousands)			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current assets	$	$ 46,740	$	$ 46,740
Noncurrent assets		166		166
Current liabilities		(1,699)		(1,699)
Total	$	$ 45,207	$	$ 45,207

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NOTE 10 Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures about Fair Value of Financial Instruments* (SFAS 107). The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to these short-term maturities of these instruments. We estimate the fair value of our convertible senior notes using quotes from third parties. The carrying amounts and fair values of the other financial instruments and derivatives at June 30, 2009 and December 31, 2008, are as follows (in thousands):

	As of June 30, 2009		As of December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior Credit Facility	$	$	$	$
Second Lien Term Loan	75,000	75,000	75,000	75,000
3.25% Convertible Senior Notes	155,404	145,985	151,723	132,948
Derivative assets (liabilities)				
Gas	46,906	46,906	55,276	55,276
Interest rate	(1,699)	(1,699)	(1,804)	(1,804)

NOTE 11 Discontinued Operations

On March 20, 2007, the Company closed the sale of substantially all of its oil and gas properties in South Louisiana with the exception of the St. Gabriel, Bayou Bouillon and Plumb Bob fields as discussed under Note 1 Assets Held for Sale. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the results of operations for the properties that were sold and for the properties that are held for sale have been reflected as discontinued operations. St. Gabriel and Bayou Bouillon fields were sold in 2008. We will accept any reasonable offer on the Plumb Bob field.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues	$ 166	$ 306	$ 223	$ 885
Expenses	77	407	123	601
Income (loss) from discontinued operations	89	(101)	100	284
Income tax expense	31		35	
Income (loss) from discontinued operations, net of tax	$ 58	$ (101)	$ 65	$ 284

The Plumb Bob field has been fully reserved and has an accrued abandonment cost liability of $1.4 million.

NOTE 12 Commitments and Contingencies

We are party to lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our consolidated financial position or results of operations or liquidity. No significant changes to these type lawsuits have occurred since December 31, 2008.

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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, 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;
- economic and competitive conditions;
- legislative and regulatory changes; and
- financial market conditions and availability of capital.

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 the Company s financial position, results of operations and cash flows.

These factors, as well as additional factors that could affect our operating results and performance are described in this report under the heading Risk Factors and in our Annual Report on Form 10-K for the year ended December 31, 2008, under the headings Business, Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations. We urge you to carefully consider those factors.

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

Overview

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 East Texas and Northwest Louisiana. Our business strategy is to provide long term growth in net asset value per share through the growth and expansion of our oil and gas reserves and production. We focus on adding reserve value through our relatively low risk development drilling program in the Cotton Valley Trend, and the pursuit of horizontal drilling opportunities in the underlying Haynesville Shale formation. The Cotton Valley Trend of East Texas and Northwest Louisiana generally provides multiple pay objectives including: the Cotton Valley, Travis Peak, Hosston, James Lime, Pettet and Haynesville Shale formations. We continue to aggressively pursue the evaluation and acquisition of prospective acreage, oil and gas drilling opportunities and potential property acquisitions.

Source of Revenues

We derive our revenues from the sale of oil and natural gas that is produced from our properties. Revenues are a function of both the volume produced and the prevailing market price at the time of sale. Production volumes, while somewhat predictable after wells have begun producing, can be impacted for various reasons. The price of oil and natural gas is a primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to manage future sales prices on a portion of our oil and natural gas production. While the derivative instruments may protect us against downward price fluctuation, the use of certain types of derivative instruments may prevent us from realizing the full benefit of upward price movements.

2nd Quarter 2009 Financial and Operating Results Include:

- We increased our oil and gas production volumes on continuing operations to 82,074 Mcfe per day, representing an increase of 22% from 67,129 Mcfe per day for the second quarter of 2008.

- We conducted drilling operations on 12 gross wells in the second quarter of 2009. The Haynesville Shale was penetrated by 9 wells.

- We reduced lease operating expense on a per unit basis by 25% from the second quarter of 2008.

Cotton Valley Trend

Our relatively low-risk development drilling program in the Cotton Valley Trend is primarily centered in and around Rusk, Panola, Angelina and Nacogdoches counties, Texas, and DeSoto, Caddo and Bienville parishes, Louisiana. We have increased our acreage position in these areas over the last three years to approximately 200,000 gross acres as of June 30, 2009. Through June 30, 2009, we have participated in the drilling and logging of 447 Cotton Valley Trend wells with a success rate in excess of 99%. We conducted drilling operations on 12 gross wells during the second quarter of 2009. Our net production volumes from our Cotton Valley Trend wells aggregated approximately 81,909 Mcfe per day in the second quarter of 2009, or approximately 23% higher than the Cotton Valley Trend production of the comparable prior year period.

Company Operated Haynesville Shale Drilling Program

We conducted drilling operations on four Haynesville horizontal wells that were in some form of drilling or completion by the quarter ended June 30, 2009. We expect to continue developing the Haynesville Shale through 2009 with the drilling and completion of approximately seven additional operated horizontal wells in East Texas and Northwest Louisiana. As of June 30, 2009, we had conducted drilling operations on a total of nine vertical and five horizontal operated wells that penetrated the Haynesville Shale. The nine vertical pilot wells were drilled early in our Haynesville Shale program and were meant to test the thickness and productivity of the Haynesville Shale throughout our acreage position. All nine wells had reached initial production by the end of the first quarter. Of the nine vertical wells, two wells were located on our Bethany Longstreet acreage in Northwest Louisiana and the remaining seven wells were drilled in the Beckville, Minden, Naconiche Creek and South Henderson fields in Texas. Daily average net production from company operated Haynesville Shale wells was 3,533 Mcfe per day for the three months ended June 30, 2009.

Chesapeake Haynesville Shale Joint Development

Through our joint development arrangement with Chesapeake Energy Corporation (Chesapeake), which covers certain of our acreage in northwest Louisiana, we will continue to operate existing production and operate any new wells drilled to the base of the Cotton Valley sand, and Chesapeake will operate any wells drilled below the base of the Cotton Valley sand, including the Haynesville Shale. As of June 30, 2009, we participated in drilling operations on twelve horizontal and one vertical well under the joint development arrangement. As of quarter end, only nine horizontal and one vertical well had reached initial production and the remaining three horizontal wells were in some form of drilling or completion. For the remainder of 2009, we and Chesapeake plan to utilize two rigs to conduct drilling operations on approximately eight gross additional Haynesville Shale horizontal wells. Daily average net production from Chesapeake operated Haynesville Shale wells grew to 12,235 Mcfe per day for the three months ended June 30, 2009.

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, 2008.

Results of Operations

The financial statements include discontinued operations presentation for our assets located in South Louisiana. See Note 11 to our consolidated financial statements.

For the three months ended June 30, 2009, we reported a net loss applicable to common stock of $36.5 million, or $1.02 per basic and diluted share, on total revenue from continuing operations of $26.3 million as compared to a net loss applicable to common stock of $40.7 million, or $1.27 per basic and diluted share, on total revenue from continuing operations of $65.2 million for the three months ended June 30, 2008. The fall in oil and gas prices period to period which decreased oil and gas revenue by approximately $53.1 million was offset by revenue from a production increase of approximately $14.5 million which resulted in the $38.6 million difference in oil and gas revenues. In conjunction with the fall of natural gas prices between the comparable periods, we recorded a $2.6 million gain on derivatives not designated as hedges in the three months ended June 30, 2009 compared to a $48.9 million loss on derivatives not designated as hedges for the three months ended June 30, 2008. We also recorded an income tax benefit on continuing operations of $21.5 million in the three months ended June 30, 2009 compared to no income tax expense for the three months ended June 30, 2008 as we increased our valuation allowance in the previous year period.

For the six months ended June 30, 2009, we reported a net loss applicable to common stock of $34.9 million, or $0.97 per basic and diluted share, on total revenue from continuing operations of $54.7 million as compared to a net loss applicable to common stock

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of $67.7 million, or $2.12 per basic and diluted share, on total revenue from continuing operations of $111.5 million for the six months ended June 30, 2008. The fall in oil and gas prices period to period which decreased oil and gas revenue by approximately $84.8 million was offset by revenue from a production increase of approximately $28.4 million which resulted in the $56.4 million difference in oil and gas revenues. In conjunction with the fall of natural gas prices between the comparable periods, we recorded a $39.6 million gain on derivatives not designated as hedges in the six months ended June 30, 2009 compared to a $73.4 million loss on derivatives not designated as hedges for the six months ended June 30, 2008. We also recorded an income tax benefit on continuing operations of $20.2 million in the six months ended June 30, 2009 compared to no income tax expense for the six months ended June 30, 2008 as we increased our valuation allowance.

Oil and Natural Gas Revenues

Revenues presented in the table and the discussion below represents revenue from sales of our oil and natural gas production volumes for continuing operations.

Summary Operating Information:

In thousands, except for price data	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Variance		2009	2008	Variance	
Revenues:								
Natural gas	$ 24,058	$ 59,436	$ (35,378)	(60)%	$ 50,977	$ 101,896	$ (50,919)	(50)%
Oil and condensate	2,176	5,416	(3,240)	(60)%	3,697	9,153	(5,456)	(60)%
Natural gas, oil and condensate	26,234	64,852	(38,618)	(60)%	54,674	111,049	(56,375)	(51)%
Operating revenues	26,263	65,173	(38,910)	(60)%	54,724	111,526	(56,802)	(51)%
Operating expenses	80,210	49,118	31,092	63%	136,217	91,868	44,349	48%
Operating income (loss)	(53,947)	16,055	(70,002)	(436)%	(81,493)	19,658	(101,151)	(515)%
Net Production:								
Natural gas (MMcf)	7,223	5,841	1,382	24%	13,768	10,874	2,894	27%
Oil and condensate (MBbls)	41	45	(4)	(9)%	86	83	3	4%
Total (Mmcfe)	7,469	6,109	1,360	22%	14,287	11,375	2,912	26%
Average daily production (Mcfe/d)	82,074	67,129	14,945	22%	78,931	62,497	16,434	26%
Average realized sales price per unit:								
Natural gas (per Mcf)	$ 3.33	$ 10.18	$ (6.85)	(67)%	$ 3.70	$ 9.37	$ (5.67)	(61)%
Oil and condensate (per Bbl)	52.98	121.51	(68.53)	(56)%	42.75	109.70	(66.95)	(61)%
Total (per Mcfe)	3.51	10.62	(7.11)	(67)%	3.83	9.76	(5.93)	(61)%

Revenues from continuing operations decreased 60% in the three months ended June 30, 2009 compared to the same period in 2008 due primarily to a substantial 67% decrease in realized sales prices. Net production increased 22% period to period. Revenues from continuing operations decreased 51% in the six months ended June 30, 2009 compared to the same period in 2008 primarily due to a 61% decrease in realized sales prices. Net production increased 26% period to period. The production increases in the three and six month periods ended June 30, 2009 over the same periods in 2008 are due to the increase in the number of wells producing in the Cotton Valley Trend and to a lesser extent, the increase in production from wells completed in the Haynesville Shale.

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Operating Expenses

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Variance		2009	2008	Variance	
Operating Expenses (in thousands)								
Lease operating expenses	$ 6,984	$ 7,669	$ (685)	(9)%	$ 15,980	$ 14,766	$ 1,214	8%
Production and other taxes	1,049	2,334	(1,285)	(55)%	2,537	3,589	(1,052)	(29)%
Transportation	2,591	2,386	205	9%	5,179	4,256	923	22%
Depreciation, depletion and amortization	36,537	29,033	7,504	26%	70,195	54,118	16,077	30%
Exploration	2,959	1,776	1,183	67%	5,179	3,779	1,400	37%
Impairment	23,490		23,490	100%	23,490		23,490	100%
General and administrative	6,713	5,920	793	13%	13,770	11,360	2,410	21%
Gain on sale of assets	(113)		(113)	100%	(113)		(113)	100%

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Variance		2009	2008	Variance	
Operating Expenses per Mcfe								
Lease operating expenses	$ 0.94	$ 1.26	$ (0.32)	(25)%	$ 1.12	$ 1.30	$ (0.18)	(14)%
Production and other taxes	0.14	0.38	(0.24)	(63)%	0.18	0.32	(0.14)	(44)%
Transportation	0.35	0.39	(0.04)	(10)%	0.36	0.37	(0.01)	(3)%
Depreciation, depletion and amortization	4.89	4.75	0.14	3%	4.91	4.76	0.15	3%
Exploration	0.40	0.29	0.11	38%	0.36	0.33	0.03	9%
Impairment	3.14		3.14	100%	1.64		1.64	100%
General and administrative	0.90	0.97	(0.07)	(7)%	0.96	1.00	(0.04)	(4)%
Gain on sale of assets	(0.02)		(0.02)	100%	(0.01)		(0.01)	100%

Lease Operating. Lease operating expense (LOE) for the three months ended June 30, 2009 was $7.0 million, a decrease of $0.7 million or 9% from the $7.7 million in the three months ended June 30, 2008. On a per unit basis, LOE decreased 25% from $1.26 to $0.94 per Mcfe for the three months ended June 30, 2009 compared to the same period in 2008. The overall cost decrease is attributed to lower saltwater disposal cost as we realized the full impact of a new series of saltwater disposal system installations in the second quarter of 2009 and lower compressor rental costs, negotiated in conjunction with current market conditions. The decrease in the unit cost between the periods is attributed to the absolute dollar cost reduction, a 22% increase in production volumes and an increasing portion of our production coming from the Haynesville Shale which carries lower production cost. LOE for the six months ended June 30, 2009 was $16.0 million, an increase of $1.2 million or 8% from the $14.8 million in the six months ended June 30, 2008. On a per unit basis, LOE decreased 14% from $1.30 to $1.12 per Mcfe for the six months ended June 30, 2009 compared to the same period in 2008. The decrease in the unit cost between the six month periods is attributed to both the cost reduction realized in the second quarter of 2009 and the 26% increase in production volumes as a result of our successful drilling program.

Production and Other Taxes. Production and other taxes for the three months ended June 30, 2009 was $1.0 million which includes production tax of $0.2 million and ad valorem tax of $0.8 million. Production tax included $0.5 million of new Tight Gas Sands (TGS) tax credits for our wells in the State of Texas. During the comparable period in 2008, production and other taxes were $2.3 million, which included production tax of $1.7 million and ad valorem tax of $0.6 million. Production tax in the three months ended June 30, 2008 included $0.8 million in TGS tax credits. Production and other taxes for the six months ended June 30, 2009 was $2.5 million which includes production tax of $1.0 million and ad valorem tax of $1.5 million. Production tax included $1.0 million of new TGS tax credits for our wells in the State of Texas. During the comparable period in 2008, production and other taxes were $3.6 million, which included production tax of $2.6 million and ad valorem tax of $1.0 million. Production tax in the six months ended June 30, 2008 included $1.6 million in TGS credits.

These TGS tax credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we have been notified of the State s approval, and we anticipate that we will incur a gradually lower production tax rate in the future as we add additional Texas Cotton Valley Trend wells to our production base and as reduced rates are approved.

Transportation. Transportation expense for the three months ended June 30, 2009 was $2.6 million ($0.35 per Mcfe) compared to $2.4 million ($0.39 per Mcfe) in the three months ended June 30, 2008. The slight increase in expense is primarily due to our higher production volumes while the lower unit costs are a function of our changing geographic production mix. Transportation expense for the six months ended June 30, 2009 was $5.2 million ($0.36 per Mcfe) compared to $4.3 million ($0.37 per Mcfe) in the six months ended June 30, 2008. The increase in expense is primarily due to our higher production volumes while the lower unit costs are a function of our changing geographic production mix.

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Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) for the three months ended June 30, 2009 increased to $36.5 million from $29.0 million for the three months ended June 30, 2008 resulting from higher levels of production and a higher DD&A rate. The average DD&A rate for the three months ended June 30, 2009 was $4.89 per Mcfe compared to $4.75 per Mcfe for the same period in 2008. DD&A for the six months ended June 30, 2009 increased to $70.2 million from $54.1 million for the six months ended June 30, 2008 with higher levels of production and a higher DD&A rate. The average DD&A rate for the six months ended June 30, 2009 was $4.91 per Mcfe compared to $4.76 per Mcfe for the same period in 2008.

We calculated the DD&A rates for the three and six months periods ended June 30, 2009 and 2008 using the December 31, 2008 and December 31, 2007 reserves, respectively. Proved developed natural gas reserves increased 39% from 108.1 Bcf at December 31, 2007 to 150.2 Bcf at December 31, 2008. Despite the increase in overall proved reserves period to period, the DD&A rate increased slightly due to the escalation of drilling costs experienced throughout the industry during 2008.

Exploration. Exploration expenses for the three months ended June 30, 2009 increased $1.2 million to $3.0 million compared to $1.8 million in the same period in 2008. In the second quarter we released two drilling rigs before the end of the contract term, for which we were assessed an early termination fee of $1.1 million. Exploration expenses for the six months ended June 30, 2009 increased $1.4 million to $5.2 million compared to $3.8 million in the same period in 2008. In addition to the drilling contract early termination charge, the six month period ended June 30, 2009 includes a $0.1 million in dry hole cost recorded in the first quarter of 2009 resulting from an unsuccessful exploration tail of a successful development well.

Impairment. We recorded impairment expense of $23.5 million for the three and six months ended June 30, 2009 primarily due to the write down of 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, 2008.

General and Administrative. General and administrative (G&A) expense increased $0.8 million or 13% to $6.7 million in the three months ended June 30, 2009 compared to $5.9 million in the same period in 2008. The increase period to period is primarily due to the increase in compensation cost relative to having a larger work force as the company head count totaled 125 in the second quarter of 2009 versus 101 in the second quarter of 2008. G&A on a per unit basis decreased to $0.90 per Mcfe from $0.97 per Mcfe as a result of a 22% increase in production volumes in the second quarter of 2009 as compared to the second quarter of 2008. Stock based compensation expense, which is a non-cash item, amounted to $1.6 million in the second quarter of 2009 compared to $1.4 million for the same period in 2008. G&A expense increased $2.4 million, or 21%, to $13.8 million in the six months ended June 30, 2009 compared to $11.4 million in the same period in 2008. The increase period to period is primarily due to the increase in compensation cost relative to having a larger work force. G&A on a per unit basis decreased to $0.96 per Mcfe from $1.00 per Mcfe as a result of a 26% increase in production volumes in the first half of 2009 as compared to the first half of 2008. Stock based compensation expense, which is a non-cash item, amounted to $3.2 million in the first half of 2009 compared to $2.7 million for the first half of 2008.

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,	
	2009	2008 (as adjusted)	2009	2008 (as adjusted)
Other income (expense):				
Interest expense	(5,298)	(6,026)	(10,506)	(11,447)
Interest income	144		383	
Gain (loss) on derivatives not designated as hedges	2,556	(48,947)	39,562	(73,434)
Income tax benefit on continuing operations	21,505		20,151	
Gain (loss) on disposal, net of tax		(120)		280
Income (loss) from discontinued operations net of tax	58	(101)	65	284
Average funded borrowings	250,000	317,088	250,000	285,632
Average funded borrowings adjusted for debt discount	229,197	289,313	228,282	257,439
Weighted average interest rate	9.3%	8.4%	9.3%	8.9%

Interest Expense. Interest expense decreased $0.7 million to $5.3 million in the three months ended June 30, 2009 compared to $6.0 million in the three months ended June 30, 2008 as a result of the lower average level of funded debt in the second quarter of 2009. Interest expense decreased $0.9 million to $10.5 million in the six months ended June 30, 2009 compared to $11.4 million in the six months ended June 30, 2008 as a result of the lower average level of funded debt in the second quarter of 2009.

The interest expense in the three and six month periods ended June 30, 2008 has been retrospectively increased by $1.6 million and $3.3 million, respectively (non-cash), as the result of our adoption of FSP APB 14-1 Accounting for Convertible Debt

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Instruments That May Be Settled in Cash upon Conversion , on January 1, 2009**.** The adoption of the standard resulted in the recognition of an additional $1.8 million and $3.6 million (non-cash) in interest expense for the three and six month periods ended June 30, 2009, respectively.

Interest Income. We invested the net proceeds from our equity offering and the sale of assets, both in July 2008, in money market funds and time deposits with certain acceptable institutions, subject to our newly implemented Short Term Investment Policy. The income earned on these investments during 2009 is reflected in the Interest income line. For more information on our Short Term Investment Policy, please see our Annual Report on Form 10-K for the year ended December 31, 2008, under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity Short Term Investments.

Gain (Loss) on Derivatives Not Designated as Hedges. Gain on derivatives not designated as hedges was $2.6 million for the three months ended June 30, 2009, including a realized gain of $27.2 million and an unrealized loss of $24.4 million for the change in fair value of our natural gas commodity contracts. The unrealized loss resulted from the roll off of existing contracts during the second quarter of 2009. The three months ended June 30, 2009 also included a loss of $0.2 million on our interest rate swap. As a comparison, loss on derivatives not designated as hedges for the three months ended June 30, 2008 was $48.9 million including a realized loss of $1.8 million and an unrealized loss of $47.6 million for the changes in fair value of our commodity contracts. The three months ended June 30, 2008 also included a net gain on interest rate swaps of $0.4 million.

Gain on derivatives not designated as hedges was $39.6 million for the six months ended June 30, 2009, including a realized gain of $48.3 million and an unrealized loss of $8.3 million for the change in fair value of our natural gas commodity contracts. The unrealized loss resulted from the roll off of existing contracts during the six months ended June 30, 2009. The six months ended June 30, 2009 also included a loss of $0.4 million on our interest rate swap. As a comparison, loss on derivatives not designated as hedges for the six months ended June 30, 2008 was $73.4 million including a realized loss of $1.4 million and an unrealized loss of $71.9 million for the changes in fair value of our commodity contracts. The six months ended June 30, 2008 also included a loss of $0.1 million on our interest rate swap.

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

Income taxes. Income tax benefit on continuing operations for the three months ended June 30, 2009 was $21.5 million which includes $1.7 million state income tax benefit. Income tax benefit on continuing operations for the six months ended June 30, 2009 was $20.2 million which includes a state income tax benefit of $1.9 million. We provided for no income taxes for the three and six months ended June 30, 2008 as a result of having had a net deferred tax asset that was fully reserved.

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,		
	2009	**2008**	**Variance**
Cash flow statement information:			
Net cash:			
Provided by operating activities	$ 63,373	$ 57,096	$ 6,277
Used in investing activities	(180,045)	(166,413)	(13,632)
Provided by (used in) financing activities	(5,508)	110,851	(116,359)
Increase (decrease) in cash	$ (122,180)	$ 1,534	$ (123,714)

Operating activities. Net cash provided by operating activities increased $6.3 million to $63.4 million for the six months ended June 30, 2009, from $57.1 million for the comparable 2008 period due primarily to the realization of $47.8 million in hedging settlements and to increased production levels during the six month period.

Investing activities. Net cash used in investing activities was $180.0 million for the six months ended June 30, 2009 compared to net cash used in investing activities of $166.4 million for the six months ended June 30, 2008. We conducted drilling operations on 36 gross wells, 22 of which penetrated the Haynesville Shale during the first six months of 2009. In comparison, we expended $175.6 million in conducting drilling operations on 80 gross wells, all of which are located in our Cotton Valley Trend, during the first six months of 2008. The cost per well increased in 2009 compared to 2008 due to drilling more expensive Haynesville Shale wells. In the 2008 comparable period, we received proceeds of $0.3 million from sales of seismic data for our St. Gabriel field and a $8.9 million cash deposit on our sale of oil and gas properties.

Financing activities. Net cash used in financing activities was $5.5 million for the six months ended June 30, 2009, versus net cash provided by financing activities of $110.9 million for the same period in 2008. In the first six months of 2009 we had virtually no financing activities since we used available cash on hand and cash flow to fund our operations. In the first six months of 2008, we borrowed $75.0 million under our Second Lien Term Loan and borrowed an additional net $40.5 million under our revolving credit facility, resulting in a net borrowing of $115.5 million offset by the payment of preferred dividends, debt issuance cost and other activity of $4.6 million.

For the year 2009, we have budgeted total capital expenditures of approximately $230 million, down from our original capital expenditure budget of $300 million, of which approximately 65%, or $150 million, is expected to be focused on drilling horizontal wells in the Haynesville Shale program in East Texas and North Louisiana, where we and our partners plan to average approximately five rigs working throughout 2009. The remainder of the budgeted amount is earmarked for horizontal wells in the James Lime in the Angelina River trend, several Cotton Valley horizontal wells in East Texas, and various leasehold and infrastructure expenditures as needed across our entire acreage block. As of June 30, 2009, we have spent approximately $153 million of our total budgeted capital expenditure for 2009. We expect to finance the remainder of our 2009 capital expenditures through a combination of cash flow from operations, from cash on hand and borrowing under our senior credit facility.

Convertible Senior Notes

In December 2006, we sold $175 million of 3.25% convertible senior notes due in December 2026. The notes mature on December 1, 2026, unless earlier converted, redeemed or repurchased. The notes are our senior unsecured obligations and will rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 3.25% annually, and interest is paid semi-annually on June 1 and December 1. Interest payments on the notes began on June 1, 2007.

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

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

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

We adopted FSP APB 14-1 on January 1, 2009. FSP APB 14-1 requires that we separately account for the liability and equity components of our convertible senior notes in a manner that will reflect our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. On January 1, 2009, we recorded a beginning of period debt discount balance of $23.3 million which represents the unamortized debt discount of the original retrospective debt discount of approximately $37.0 million and an equity component net of tax of $23.9 million. As of June 30, 2009 the $175 million notes were carried on the balance sheet as $155.4 million with a debt discount balance of $19.6 million. This remaining amount of debt discount will be amortized using the effective interest rate method based upon an original 5 year term through December 1, 2011. Amortization of debt discount for the three and six months ended June 30, 2009 was $1.9 million and $3.7 million, respectively.

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 October 1, 2010 and, under certain conditions related to our refinancing of the Second Lien Term Loan the maturity can be extended to 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 convertible senior notes. Revolving borrowings under the Senior Credit Facility are limited to, and subject to periodic redeterminations of the borrowing base. The initial borrowing base was established at $175 million. The borrowing base interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 0.75% to 1.50%, or LIBOR plus 2.25% to 3.00%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on each April 1 and October 1 beginning on October 1, 2009. The current availability under the credit facility is $175 million.

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

The terms of the Senior Credit Facility requires 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

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this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. The 3.25% convertible senior notes are excluded from the calculation of Total Debt for the purpose of computing this ratio).

Second Lien Term Loan

On January 16, 2008, we entered into a new Second Lien Term Loan Agreement which provides for a 3-year, secured, non-revolving loan of $75.0 million and is due in a single maturity on December 31, 2010. We had no rights to prepay in the first year. Voluntary prepayment rights in the second year are at 101% of par, and thereafter at par. Interest on the Second Lien Term Loan accrues at a rate of LIBOR plus 550 basis points and is payable quarterly in arrears. As of June 30, 2009, we were in compliance with all of the financial covenants of our Second Lien Term Loan. The terms of the Second Lien Term Loan Agreement contain financial covenants which include:

- an asset coverage ratio (defined as the present value of proved reserves discounted 10% to total debt, which excludes 3.25% convertible senior notes) of not less than 1.5 to 1.0;

- a total debt to EBITDAX ratio of not more than 3.0 to 1.0 (total debt excludes the 3.25% convertible senior notes); and

- an EBITDAX to interest expense ratio of not less than 3.0 to 1.0.

Capped Call Option Transactions

On December 10, 2007 using the proceeds of a public offering, we purchased capped call options on our shares of common stock. The capped call option transactions covered, subject to customary anti-dilution adjustments, approximately 5.8 million shares of our common stock, and each of them was divided into a number of tranches with differing expiration dates. Approximately 77,333 options per trading day will expire over each of three separate 25 consecutive trading day settlement periods which began on May 18, 2009, and again beginning on November 16, 2009 and May 18, 2010, respectively.

On the 25 consecutive trading days from May 18, 2009 through June 22, 2009, the first of the three tranches of options expired. During this period, the price of our common stock closed above the lower call strike price on all trading days resulting in recoupment of 246,134 shares of our common stock.

Adoption of FSP APB 14-1 Convertible Debt Instruments That May Be Settled in Cash Upon Conversion APIC

FSP APB 14-1 requires the issuer of certain convertible debt instruments that may be settled in cash on conversion to separately account for the liability and equity components in a manner that reflects the issuer s nonconvertible debt borrowing rate. As a result of the adoption of the standard, additional paid in capital was increased by $22.8 million, to reflect the deemed equity portion of the convertible notes. We also recorded a beginning of period adjustment to retained earnings of $8.1 million, representing the cumulative effect on retained earnings of the retrospective application of FSP APB 14-1 relating to after tax interest expense.

Accounting Pronouncements

See Note 1 Description of Business and Significant Accounting Policies New Accounting Pronouncements to our consolidated financial statements for a discussion of recently issued pronouncements.

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 or 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, 2008, includes a discussion of our critical accounting 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 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.

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, 2009, the commodity hedges we utilized were in the form of:

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

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

(c) basis swap, 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 2009. The fair value of the natural gas hedging contracts in place at June 30, 2009, resulted in a net current asset of $46.7 million and a net non-current asset of $0.2 million. Based on oil and gas pricing in effect at June 30, 2009, a hypothetical 10% increase in oil and gas prices would have resulted in a derivative asset of $41.7 million while a hypothetical 10% decrease in oil and gas prices would have increased the derivative asset to $52.2 million. See Note 8 Derivative Activities to our consolidated financial statements for additional information.

Interest Rate Risk

We have several variable-rate debt obligations that expose us to the effects of changes in interest rates. To partially reduce our exposure to interest rate risk, from time to time we enter into interest rate swap agreements. We entered into interest rate derivative swap agreements in the second quarter of 2008, whereby we contracted a notional amount of $75.0 million at a fixed rate of 3.191% for the period April 2008 to April 2010. We have not designated these swaps as a hedge. At June 30, 2009, we had the following interest rate swaps in place with BNP Paribas and Bank of Montreal:

Effective Date	Maturity Date	Libor Swap Rate	Notional Amount (Millions)	Fair Value (Dollars)
4/22/2008	4/22/2010	3.19%	$ 25.0	$ (566,554)
4/22/2008	4/22/2010	3.19%	50.0	(1,132,353)
				$ (1,698,907)

The fair value of the interest rate swap contracts in place at June 30, 2009, resulted in a liability of $1.7 million. Based on interest rates at June 30, 2009, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the liability.

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, 2009, 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

There were no changes in our system of internal control over financial reporting that occurred during our first quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1A Risk Factors

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

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Item 4 Submission of Matters to a Vote of Security Holders

Our Annual Meeting of Stockholders was held on May 28, 2009. Set forth below is a brief description of each matter acted upon at the meeting and the number of votes cast for, against or withheld, and abstaining or not voting as to each matter:

		For	Against	Abstained or Withheld
(i)	Election of Class I Directors			
	Henry Goodrich	32,327,452		1,041,140
	Patrick E. Malloy III	33,190,193		178,399
	Michael J. Perdue	33,190,193		178,399
(ii)	Ratification of the appointment of Ernst & Young LLP as the company s independent registered public accounting firm for 2009.	33,334,473		18,108

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Item 6 Exhibits

*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.

* 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 and thereunto duly authorized.

GOODRICH PETROLEUM CORPORATION

(Registrant)

Date: August 6, 2009	By: /s/ Walter G. Goodrich Walter G. Goodrich Vice Chairman & Chief Executive Officer
Date: August 6, 2009	By: /s/ David R. Looney David R. Looney Executive Vice President & Chief Financial Officer

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GOODRICH PETROLEUM CORPORATION LIST OF EXHIBITS TO FORM 10-Q

FOR QUARTER ENDED JUNE 30, 2009

EXHIBIT NO.	DESCRIPTION OF EXHIBIT
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* Filed herewith
** Furnished herewith