GOODRICH PETROLEUM CORP
Form 10-Q
August 07, 2012
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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, 2012

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

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

801 Louisiana, Suite 700

Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

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

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

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

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

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

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

The number of shares outstanding of the Registrant s common stock as of August 1, 2012 was 36,391,165.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

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PART 1 FINANCIAL INFORMATION

Item 1 Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	June 30, 2012 (unaudited)	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,955	$ 3,347
Accounts receivable, trade and other, net of allowance	9,560	7,594
Income taxes receivable	147	340
Accrued oil and natural gas revenue	14,728	20,420
Fair value of oil and natural gas derivatives	40,070	56,486
Inventory	4,255	8,627
Prepaid expenses and other	1,418	4,315
Total current assets	72,133	101,129
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	1,678,180	1,542,406
Furniture, fixtures and equipment	5,977	5,654
	1,684,157	1,548,060
Less: Accumulated depletion, depreciation and amortization	(896,351)	(824,894)
Net property and equipment	787,806	723,166
Fair value of oil and natural gas derivatives	1,302	
Deferred tax assets	13,944	19,720
Deferred financing cost and other	17,673	18,088
TOTAL ASSETS	$ 892,858	$ 862,103
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 52,189	$ 46,095
Accrued liabilities	45,716	43,874
Accrued abandonment costs	474	5,176
Deferred tax liabilities current	13,944	19,720
Total current liabilities	112,323	114,865
LONG-TERM DEBT	626,510	566,126
Accrued abandonment costs	17,320	12,249
Fair value of oil and natural gas derivatives	6,059	17,420
Transportation obligation	7,213	7,743
Total liabilities	769,425	718,403

Commitments and contingencies (See Note 8)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized: Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000 shares	2,250	2,250
Common stock: $0.20 par value, 100,000,000 shares authorized; issued and outstanding 36,388,801 and 36,378,508 shares, respectively	7,278	7,276
Treasury stock (530 and 44,826 shares, respectively)	(8)	(689)
Additional paid in capital	644,795	641,790
Retained earnings (accumulated deficit)	(530,882)	(506,927)
Total stockholders equity	123,433	143,700
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 892,858	$ 862,103

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, Except Per Share Amounts)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
REVENUES:				
Oil and natural gas revenues	$ 41,411	$ 52,434	$ 86,788	$ 93,352
Other	(65)	437	(134)	750
	41,346	52,871	86,654	94,102
OPERATING EXPENSES:				
Lease operating expense	6,695	5,215	15,049	10,118
Production and other taxes	2,087	1,645	4,080	2,595
Transportation and processing	3,522	2,301	7,650	4,687
Depreciation, depletion and amortization	34,562	30,927	66,840	55,886
Exploration	2,019	2,325	4,232	4,741
Impairment		1,050	2,662	1,050
General and administrative	6,690	7,328	14,611	15,578
Gain on sale of assets	(72)		(72)	(236)
	55,503	50,791	115,052	94,419
Operating income (loss)	(14,157)	2,080	(28,398)	(317)
OTHER INCOME (EXPENSE):				
Interest expense	(13,089)	(12,965)	(26,002)	(23,793)
Interest income and other	1	10	1	22
Gain on derivatives not designated as hedges	24,043	10,954	33,468	944
Gain on extinguishment of debt		3		58
	10,955	(1,998)	7,467	(22,769)
Income (loss) before income taxes	(3,202)	82	(20,931)	(23,086)
Income tax benefit				
Net income (loss)	(3,202)	82	(20,931)	(23,086)
Preferred stock dividends	1,512	1,512	3,024	3,024
Net loss applicable to common stock	$ (4,714)	$ (1,430)	$ (23,955)	$ (26,110)
PER COMMON SHARE				
Net loss applicable to common stock - basic	$ (0.13)	$ (0.04)	$ (0.66)	$ (0.72)
Net loss applicable to common stock - diluted	$ (0.13)	$ (0.04)	$ (0.66)	$ (0.72)
Weighted average common shares outstanding - basic	36,366	36,110	36,352	36,093
Weighted average common shares outstanding - diluted	36,366	36,110	36,352	36,093

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (20,931)	$ (23,086)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	66,840	55,886
Unrealized loss on derivatives not designated as hedges	3,753	12,168
Impairment	2,662	1,050
Amortization of leasehold costs	2,551	2,977
Share based compensation (non-cash)	3,035	3,177
Gain on sale of assets	(72)	(236)
Gain on extinguishment of debt		(58)
Amortization of finance cost and debt discount	6,272	8,203
Amortization of transportation obligation	589	
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	(1,964)	441
Income taxes receivable	193	3,882
Accrued oil and natural gas revenue	5,692	(8,040)
Inventory	4,371	1,088
Prepaid expenses and other	3,003	175
Accounts payable	6,095	2,259
Accrued liabilities	(4,159)	8,035
Net cash provided by operating activities	77,930	67,921
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(131,777)	(193,508)
Proceeds from sale of assets	39	172
Net cash used in investing activities	(131,738)	(193,336)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from bank borrowings	63,000	52,500
Principal payments of bank borrowings	(7,500)	(30,000)
Preferred stock dividends	(3,024)	(3,024)
Debt issuance costs	(56)	(9,094)
Other	(20)	(363)
Exercise of stock options and warrants	16	
Proceeds from high yield offering		275,000
Repurchase of convertible notes		(150,277)
Cash restricted for repurchase of convertible notes		(26,568)
Net cash provided by financing activities	52,416	108,174
DECREASE IN CASH AND CASH EQUIVALENTS	(1,392)	(17,241)

CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		3,347		17,788
CASH AND CASH EQUIVALENTS, END OF PERIOD	$	1,955	$	547

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Significant Accounting Policies

Goodrich Petroleum Corporation (together with its subsidiary, we, our, or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) South Texas, which includes the Eagle Ford Shale, (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Taylor Sand, and (iii) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale.

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

The accompanying consolidated financial statements of the Company should be read in conjunction with the consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2011. The results of operations for the three and six months ended June 30, 2012 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 US GAAP.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase.

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

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of each of June 30, 2012 and December 31, 2011, our allowance for doubtful accounts was immaterial.

Inventory Inventory consists of casing and tubulars that are expected to be used in our drilling program and oil in storage tanks. Inventory is carried on our Consolidated Balance Sheets at the lower of cost or market.

Property and Equipment We follow the successful efforts method of accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and natural gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases. Development costs are capitalized, including the costs of unsuccessful development wells.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

Level 1 Inputs unadjusted quoted market prices in active markets for identical assets or liabilities. Included in this level is our Senior Notes;

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

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

At each of June 30, 2012 and December 31, 2011, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

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

As of June 30, 2012, we have interests in oil and natural gas properties totaling $786.2 million, net of accumulated depletion, which we account for under the successful efforts method. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimated future net cash flows generated from our oil and natural gas properties by using oil and natural gas futures prices published by the New York Mercantile Exchange (NYMEX).

We determined during the first quarter of 2012 that the carrying amount of certain of our non-core oil and natural gas properties were not recoverable from future cash flows due to declining natural gas prices and, therefore, we recorded an impairment of $2.7 million for the three months ended March 31, 2012. These impairment charges reduced the fields carrying value to an estimated fair value of $0.9 million. No impairments were recorded for the three months ended June 30, 2012.

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

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Transportation Obligation We entered into a gas gathering agreement with an independent service provider, effective July 27, 2010. The agreement is scheduled to remain in effect for a period of ten years and requires the service provider to construct pipelines and facilities to connect our wells to the service provider s gathering system in our Eagle Ford Shale area of South Texas. In compensation for the services, we agreed to pay the service provider 110% of the total capital cost incurred by the service provider to construct new pipelines and facilities. The service provider will bill us for 20 percent of the accumulated unpaid capital costs annually.

We account for the agreement by recording a long-term asset, included in Deferred financing cost and other on our Consolidated Balance Sheets. The asset is amortized using the units-of-production method and the amortization expense is included in Transportation and processing on our Consolidated Statements of Operations. The related current and long-term liabilities are presented on our Consolidated Balance Sheets in Accrued liabilities and Transportation obligation, respectively.

Asset Retirement Obligations We follow the accounting standard related to accounting for asset retirement obligations. These obligations are related to the abandonment and site restoration requirements that result from the acquisition, construction and development of our oil and natural gas properties. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in depreciation, depletion and amortization on our Consolidated Statements of Operations.

Revenue Recognition Oil and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. We record a liability or an asset for natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At each of June 30, 2012 and December 31, 2011, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

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

Income Taxes We account for income taxes, as required, under the 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 carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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

Earnings Per Share Basic income per common share is computed by dividing net income available to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income available to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive stock options and restricted stock calculated using the Treasury Stock method and the potential dilutive effect of the conversion of shares associated with our Series B Convertible Preferred Stock, 3.25% Convertible Senior Notes due 2026 and 5% Convertible Senior Notes due 2029.

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

Share-Based Compensation We account for our share-based transactions using fair value and recognize compensation expense over the requisite service period. The fair value of each option award is estimated using a Black-Scholes option valuation model with various assumptions based on our estimates. Our assumptions include expected volatility, expected term of option, risk-free

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends, so the dividend yield is zero. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

Guarantee On March 2, 2011, we issued and sold $275,000,000 aggregate principal amount of our 8.875% Senior Notes due 2019 (the 2019 Notes). The 2019 Notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiary, Goodrich Petroleum Company, L.L.C.

Goodrich Petroleum Corporation, as the parent company (the Parent Company), has no independent assets or operations. The guarantee is full and unconditional, and the Parent Company has no other subsidiaries. In addition, there are no restrictions on the ability of the Parent Company to obtain funds from its subsidiary by dividend or loan. Finally, the Parent Company s wholly-owned subsidiary does not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by the subsidiary without the consent of a third party.

New Accounting Pronouncements

ASU 2011-04 Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. - In May 2011, the Financial Accounting Standards Board (the FASB) issued additional guidance intended to result in convergence between US GAAP and International Financial Reporting Standards (IFRS) requirements for measurement of and disclosures about fair value. The amendments are not expected to have a significant impact on companies applying US GAAP. Principal provisions of the amendments include: (i) application of the highest and best use is relevant only when measuring fair value for non-financial assets and liabilities; (ii) a prohibition on grouping financial instruments for purposes of determining fair value, except when an entity manages market and credit risks on the basis of the entity s net exposure to the group; (iii) an extension of the prohibition against the use of a blockage factor to all fair value measurements (that prohibition currently applies only to financial instruments with quoted prices in active markets); (iv) guidance that fair value measurement of equity instruments should be made from the perspective of a market participant that holds that instrument as an asset; and (v) a requirement that for recurring Level 3 fair value measurements, entities disclose quantitative information about unobservable inputs, a description of the valuation process used and qualitative details about the sensitivity of the measurements. In addition, for Balance Sheet items not carried at fair value but for which fair value is disclosed, entities will be required to disclose the Level within the fair value hierarchy that applies to the fair value measurement disclosed. This guidance is effective for interim and annual periods beginning after December 15, 2011. We have adopted this guidance effective January 1, 2012. The adoption of this guidance did not have an impact on the Company s fair value measurements, financial condition, results of operations or cash flows.

ASU 2011-05 Comprehensive Income: Presentation of Comprehensive Income - In June 2011, the FASB issued guidance intended to eliminate the option to report other comprehensive income and its components in the statement of changes in equity. ASU 2011-05 requires that all non-owner changes in stockholders equity be presented in either a single continuous statement of comprehensive income or in two separate but consecutive statements. This new guidance is to be applied retrospectively for interim and annual periods beginning after December 15, 2011. The adoption of this guidance does not have an impact on the Company s financial condition, results of operations or cash flows.

ASU 2011-11 Balance Sheet: Disclosures about Offsetting Assets and Liabilities. - In December 2011, the FASB issued guidance intended to result in convergence between US GAAP and IFRS requirements for offsetting (netting) assets and liabilities presented in the statements of financial position. The guidance requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The disclosure affects all entities with financial instruments and derivatives that are either offset on the balance sheet in accordance with ASC 210-20-45 or ASC 815-10-45, or subject to a master netting arrangement, irrespective of whether they are offset on the balance sheet. This information will enable users of an entity s financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. The guidance is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods. Entities should provide the disclosures required by this ASU retrospectively for all comparative periods presented. We will adopt this guidance effective January 1, 2013. The adoption of this guidance is not expected to have an impact on the Company s financial condition, results of operations or cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the six months ended June 30, 2012, is as follows (in thousands):

Beginning balance	$ 17,425
Liabilities incurred	357
Revisions in estimated liabilities	
Liabilities settled	(551)
Accretion expense	567
Dispositions	(4)
Ending balance	17,794
Current liability	474
Long term liability	$ 17,320

NOTE 3 Debt

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

	June 30, 2012			December 31, 2011		
	Principal	Carrying Amount	Fair Value (1)	Principal	Carrying Amount	Fair Value (1)
Senior Credit Facility	$ 158,000	$ 158,000	$ 158,000	$ 102,500	$ 102,500	$ 102,500
3.25% Convertible Senior Notes due 2026	429	429	429	429	429	429
5.0% Convertible Senior Notes due 2029 (2)	218,500	193,081	203,751	218,500	188,197	201,785
8.875% Senior Notes due 2019	275,000	275,000	271,013	275,000	275,000	243,898
Total debt	$ 651,929	$ 626,510	$ 633,193	$ 596,429	$ 566,126	$ 548,612

(1) The carrying amount for the Senior Credit Facility represents fair value because the variable interest rates are reflective of current market conditions and the carrying amount of the 3.25% Convertible Senior Notes due 2026 represents fair value because the last transacted activity was at par; otherwise, fair value was obtained by direct market quotes within Level 1 of the fair value hierarchy.

(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was $25.4 million and 30.3 million as of June 30, 2012 and December 31, 2011 respectively.

The following table summarizes the total interest expense (contractual interest expense, amortization of debt discount and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011

	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate
Senior Credit Facility	1,336	3.7%	852		2,496	3.9%	1,711	
3.25% Convertible Senior Notes due 2026	3	3.3%	614	8.9%	7	3.3%	3,397	9.2%
5.0% Convertible Senior Notes due 2029	5,423	11.3%	5,175	11.4%	10,846	11.4%	10,350	11.5%
8.875% Senior Notes due 2019	6,327	9.2%	6,324	9.2%	12,653	9.2%	8,327	9.2%

* An Effective Interest Rate Calculation is not meaningful for the three and six months ended June 30, 2011 since there were only minimal to no amounts borrowed under the Senior Credit Facility during the period.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (including all amendments, the Senior Credit Facility) that replaced our previous facility. Total lender commitments under the Senior Credit Facility are $600 million. The Senior Credit Facility matures on July 1, 2014 subject to automatic extension to February 25, 2016, if we prepay or escrow proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029 (the 2029 Notes). Borrowings under the Senior Credit Facility are limited to, and subject to, periodic redeterminations of the borrowing base, which was $265 million as of June 30, 2012. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on each April 1 and October 1. Interest on borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, in each case depending on borrowing base utilization. As of June 30, 2012, we had $158 million outstanding under the Senior Credit Facility. Substantially all our assets are pledged as collateral to secure our obligations under the Senior Credit Facility.

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

Current Ratio of 1.0/1.0;

Ratio of EBITDAX to cash Interest Expense of not less than 2.5/1.0 for the trailing four quarters ; and

Total Debt no greater than 4.0 times EBITDAX for the trailing four quarters.

As used in connection with the Senior Credit Facility, EBITDAX is earnings before interest expense, income tax, depreciation, depletion and amortization, exploration expense, stock based compensation and impairment of oil and natural gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives not designated as hedges but exclude unrealized gains (losses) from derivatives not designated as hedges.

We were in compliance with all the financial covenants of the Senior Credit Facility as of June 30, 2012.

8.875% Senior Notes due 2019

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

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

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

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of our 2029 Notes. The notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The 2029 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2029 Notes accrue interest at a rate of 5% annually, and interest is paid semi-annually in arrears on April 1 and October 1 of each year.

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We may not redeem the 2029 Notes before October 1, 2014. On or after October 1, 2014, we may redeem all or a portion of the 2029 Notes for cash, and the investors may require us to repurchase the 2029 Notes on each of October 1, 2014, 2019 and 2024. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

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

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

We separately account for the liability and equity components of our 2029 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. Upon issuance of the notes in September 2009, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion, we recorded a debt discount of $49.4 million, thereby reducing the carrying the value of $218.5 million notes on the December 31, 2009 balance sheet to $171.1 million and recorded an equity component net of tax of $32.1 million. The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014.

3.25% Convertible Senior Notes Due 2026

During the year ended December 31, 2011, we repurchased $174.6 million of our 3.25% Convertible Senior Notes due 2026 (the 2026 Notes) using a portion of the net proceeds from the issuance of our 2019 Notes. At June 30, 2012, $0.4 million of the 2026 Notes remained outstanding. Holders may present to us for redemption the remaining outstanding 2026 Notes on December 1, 2016 and December 1, 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 2026 Notes are convertible into shares of our common stock at a rate equal to the sum of:

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

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

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NOTE 4 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, 2012 and 2011. The following table sets forth information related to the computations of basic and diluted loss per share (amounts in thousands, except per share data):

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
	(Amounts in thousands, except per share data)			
Basic loss per share:				
Loss applicable to common stock	$ (4,714)	$ (1,430)	$ (23,955)	$ (26,110)
Weighted average shares of common stock outstanding	36,366	36,110	36,352	36,093
Basic loss per share	$ (0.13)	$ (0.04)	$ (0.66)	$ (0.72)
Diluted loss per share:				
Loss applicable to common stock	$ (4,714)	$ (1,430)	$ (23,955)	$ (26,110)
Dividends on convertible preferred stock (1)				
Interest and amortization of loan cost on senior convertible notes, net of tax (2)				
	$ (4,714)	$ (1,430)	$ (23,955)	$ (26,110)
Weighted average shares of common stock outstanding	36,366	36,110	36,352	36,093
Assumed conversion of convertible preferred stock (1)				
Assumed conversion of convertible senior notes (2)				
Stock options and restricted stock (3)				
Weighted average diluted shares outstanding	36,366	36,110	36,352	36,093
Diluted loss per share	$ (0.13)	$ (0.04)	$ (0.66)	$ (0.72)
(1) Common shares issuable upon assumed conversion of convertible preferred stock were not presented as they would have been anti-dilutive.	3,587,850	3,587,850	3,587,850	3,587,850
(2) Common shares issuable upon assumed conversion of the 2026 Notes and the 2029 Notes were not presented as they would have been anti-dilutive.	6,310,974	7,511,157	6,310,974	7,511,157
(3) Common shares issuable on assumed conversion of restricted stock and employee stock option were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	216,846	196,536	199,001	178,093

NOTE 5 Income Taxes

We recorded no income tax expense or benefit for the three and six months ended June 30, 2012. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed, and, as a result, we continue to maintain a full valuation allowance for our net deferred assets as of June 30, 2012.

As of June 30, 2012, we have no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2011.

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NOTE 6 Stockholders Equity

Restricted Stock

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Restricted shares vested	2,550	4,639
Weighted average grant date value per share	$ 18.44	$ 22.16

Stock Options

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Options exercised		4,000
Weighted average exercise price		$ 4.11

NOTE 7 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 Statements of Operations.

The following table summarizes the realized and unrealized gains and losses we recognized on our oil and natural gas derivatives for the three and six month periods ended June 30, 2012 and 2011.

	Three Months Ended June 30,		Six Months Ended June 30,	
Oil and Natural Gas Derivatives (in thousands)	**2012**	**2011**	**2012**	**2011**
Realized gain on oil and natural gas derivatives	$ 21,328	$ 5,964	$ 37,221	$ 13,112
Unrealized gain (loss) on oil and natural gas derivatives	2,715	4,990	(3,753)	(12,168)
Total gain on oil and natural gas derivatives	$ 24,043	$ 10,954	$ 33,468	$ 944

Commodity Derivative Activity

We enter into swap contracts, costless collars or other derivative agreements from time to time to manage 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, 2012, the commodity derivatives we used were in the form of:

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

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

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

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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 to seasonality of demand and other factors beyond our control. Domestic crude oil and natural 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 routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties. As of June 30, 2012, our open forward positions on our outstanding commodity derivative contracts, all of which were with BNP Paribas, Bank of Montreal, Royal Bank of Canada and JPMorgan Chase Bank, N.A., were as follows:

Contract Type	Daily Volume	Total Volume	Average Floor/Cap	Fair Value at June 30, 2012 (in thousands)
Natural gas collars (MMBtu)				
2012	40,000	14,640,000	$ 6.00-$7.09	$ 22,335
			Fixed Price	
Natural gas swaps (MMBtu)				
2012	20,000	7,320,000	$5.35	8,762
Natural gas swaptions (MMBtu)				
2013	20,000	7,300,000	$5.35	
2014	20,000	7,300,000	$5.35	(1,350)
Oil swaps (BBL)				
2012	3,000	1,037,500	$97.30-$104.25	
2013	500	182,500	$103.15	
2013 (1)	500	15,500	$101.50	11,662
Oil swaptions (BBL)				
2013	2,500	912,500	$97.30-$112.00	
2014	1,500	547,500	$97.30-$101.00	(6,096)
			Total	$ 35,313

(1) Swap is only for the month of January.

During the second quarter of 2012, we entered into the following new derivative contracts.

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 104.25	May 1, 2012	December 31, 2012
Oil swap (BBL)	500	$ 103.15	January 1, 2013	December 31, 2013

Subsequent to June 30, 2012, we entered into the following new derivative contract.

Contract Type	Daily Volume	Strike Price	Contract Start Date	Contract Termination
Oil swap (BBL)	500	$ 92.50	August 1, 2012	December 31, 2013

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each level as of June 30, 2012 (in thousands). We measure the fair value of our commodity derivative contracts by applying the income approach. See Note 1 Description of Business and Significant Accounting Policies - Fair Value Measurement for our discussion for inputs used and valuation techniques for determining fair values.

	June 30, 2012 Fair Value Measurements Using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Current Assets Commodity Derivatives	$	$ 40,070	$	$ 40,070
Non-current Assets Commodity Derivatives		1,302		1,302
Non-current Liabilities Commodity Derivatives		(6,059)		(6,059)
Total	$	$ 35,313	$	$ 35,313

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 8 Commitments and Contingencies

As of June 30, 2012, we do not have any changes in material commitments and contingencies, including outstanding and pending litigation.

NOTE 9 Acquisitions

In the six months ended June 30, 2012, we acquired rights to an additional 55,000 gross (52,000 net) acres in undeveloped leases in the Tuscaloosa Marine Shale for a total of $16.7 million.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

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

- litigation matters;
- pursuit of potential future acquisition opportunities;
- sources of funding for exploration and development;
- general economic conditions, either nationally or in the jurisdictions in which we do business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes**,** hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;
- the creditworthiness of our financial counterparties and operation partners;
- the securities, capital or credit markets; and
- our ability to repay our debt.

For additional information regarding known material factors that could cause our actual results to differ from projected results, please read the rest of this report and Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of properties primarily in (i) South Texas, which includes the Eagle Ford Shale Trend, (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Taylor Sand and (iii) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale.

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

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

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

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

Business Strategy

Our business strategy is to provide long-term growth in reserves on a cost-effective basis. We focus on adding reserve value through the development of our Haynesville Shale, Cotton Valley Taylor Sand, Eagle Ford Shale Trend and Tuscaloosa Marine Shale acreage and the timely development of our large, relatively low-risk development program in the Southeast and Northwest Louisiana, East and South Texas and Southwest Mississippi area. We regularly evaluate possible acquisitions of prospective acreage and oil and natural gas drilling opportunities.

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

Develop existing property base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest rate of return potential. We intend to develop our multi-year inventory of drilling locations on our acreage in the Eagle Ford Shale Trend, Haynesville Shale, Cotton Valley Taylor Sand and Tuscaloosa Marine Shale in order to develop our oil and natural gas reserves.

Increase our oil production. During the past year, we have concentrated on increasing our crude oil production and reserves by investing and drilling in the Eagle Ford Shale Trend and Tuscaloosa Marine Shale. We intend to take advantage of the current favorable sales price of oil compared to the relative sales price of natural gas. We increased our oil production as a percentage of total production from 8% and 7% for the three and six months ended June 30, 2011, respectively to 18% and 17% for the three and six months June 30, 2012, respectively.

Expand acreage position in shale plays. As of June 30, 2012, we have acquired approximately 132,300 net acres in the Tuscaloosa Marine Shale in Southeastern Louisiana and Southwestern Mississippi. We continue to concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in areas that exhibit characteristics similar to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal non-core properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on maximizing cash flow margins. We intend to maximize operating cash flow by focusing on higher-margin oil development in the Eagle Ford Shale Trend and the Tuscaloosa Marine Shale. In the current commodity price environment, our Eagle Ford Shale Trend and Tuscaloosa Marine Shale assets offer more attractive cash flow margins than our natural gas assets.

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Maintain financial flexibility. As of June 30, 2012, we have a borrowing base of $265 million under our $600 million Senior Credit Facility, of which $158 million was outstanding. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. We have historically funded growth through cash flow from operations, debt, equity and equity-linked security issuances, divestments of non-core assets and entering into strategic joint ventures. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including fixed price swaps, swaptions and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy.

Primary Operating Areas

Eagle Ford Shale Trend

During the first half of 2012, we continued drilling operations on our acreage in the Eagle Ford Shale Trend. We entered the Eagle Ford Shale Trend in April 2010. Our leasehold position is located in both La Salle and Frio Counties, Texas. We hold approximately 53,500 gross (38,200 net) acres as of June 30, 2012, all of which are either producing from or prospective for the Eagle Ford Shale. During the first half of 2012, we conducted drilling operations on approximately 20 gross (13 net) Eagle Ford Shale Trend wells. In 2012, we plan to spend approximately $175 million representing 70% of our capital budget, on 32 gross (22 net) wells in the Eagle Ford Shale Trend. During the first half of 2012, we spent approximately $91.6 million on drilling and completion, leasehold and infrastructure capital expenditures in the Eagle Ford Shale Trend.

Tuscaloosa Marine Shale

We hold approximately 156,900 gross (132,300 net) acres in the Tuscaloosa Marine Shale as of June 30, 2012, an emerging oil shale play. Our acreage is located in East Feliciana, West Feliciana, St. Helena, Concordia and Washington Parishes in Southeastern Louisiana and Wilkinson, Pike and Amite Counties in Southwestern Mississippi. During the year we added approximately 55,000 gross (52,000 net) acres in the Trend. During the first half of 2012, we conducted drilling operations on approximately three gross (one net) Tuscaloosa Marine Shale wells. In 2012, we plan to spend approximately $20 million to drill and complete four gross (two net) Tuscaloosa Marine Shale wells. During the first half of 2012, we spent approximately $21.6 million in the Tuscaloosa Marine Shale Trend, which included $16.7 million for leasehold costs.

Haynesville Shale Trend

Our relatively low risk development drilling program in this trend is primarily centered in Rusk, Panola, Angelina and Nacogdoches counties, Texas and DeSoto and Caddo Parishes, Louisiana. We hold approximately 126,500 gross (81,700 net) acres as of June 30, 2012 producing from and prospective for the Haynesville Shale. Our net production volumes from our Haynesville Shale wells aggregated approximately 45,400 Mcfe per day in the second quarter of 2012, or approximately 50% of our total production for the quarter. In early 2012, we reduced our capital spending budget in the Haynesville Shale Trend to approximately $27.5 million due to low natural gas prices and we currently have minimal to no capital dollars budgeted for the second half of 2012. During the first half of 2012, we conducted drilling operations on approximately six gross (three net) Haynesville Shale Trend wells, which included five gross (two net) non-operated wells that were drilled in 2011 but were cased in early 2012. As of June 30, 2012, we have approximately 14 gross (six net) Haynesville Shale Trend wells drilled and waiting on completion.

Core Haynesville Shale

Our core Haynesville Shale drilling program is primarily concentrated in the Bethany-Longstreet and Greenwood-Waskom fields in Caddo and DeSoto Parishes in Northwest Louisiana. Our core Haynesville Shale drilling activity includes both operated and non-operated drilling in and around our core acreage positions in Northwest Louisiana. We currently hold approximately 32,000 gross (15,600 net) acres as of June 30, 2012. Our net production volumes from our core Haynesville Shale wells totaled approximately 36,200 Mcfe per day in the second quarter of 2012, or approximately 40% of our total production for the quarter. For the remainder of 2012, we have minimal to no capital dollars budgeted for Core Haynesville Shale drilling and completion activity.

Shelby Trough / Angelina River Trend

We operate all of our drilling activities in this area, which is primarily located in Nacogdoches, Angelina and Shelby counties, Texas. The Company currently holds approximately 41,200 gross (29,700 net) acres as of June 30, 2012. Our net production volumes from the Shelby Trough wells totaled approximately 5,500 Mcfe per day in the second quarter of 2012, or approximately 6% of our total production for the quarter. During the first half of 2012, we conducted drilling operations on one 100% owned Angelina River Trend well, and we have currently deferred completion activity on that well until 2013. For the remainder of 2012, we have minimal to no capital dollars budgeted for Angelina River Trend drilling and completion activity.

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Overview of Second Quarter 2012 Results

Second Quarter 2012 financial and operating results included:

- Our oil and condensate production for the second quarter of 2012 increased to 18% of our total production compared to 8% of our total production in the second quarter of 2011.
- Our oil revenue for the second quarter of 2012 increased to 61% of our total oil and natural gas revenue compared to 25% of our oil and natural gas revenue in the second quarter of 2011.
- We conducted drilling operations on 15 gross (10 net) wells in the second quarter of 2012, including 13 gross (nine net) Eagle Ford Shale Trend wells in South Texas and two gross (one net) in the Tuscaloosa Marine Shale Trend. We added 10 gross (five net) wells to production in the second quarter of 2012, of which seven gross (4.5 net) were in the Eagle Ford Shale Trend. As of June 30, 2012, we had 18 gross (nine net) wells drilled and waiting on completion mostly comprised of 14 gross (six net) Haynesville Shale Trend wells.
- We completed our first non-operated well and began drilling operations on our first operated well in the Tuscaloosa Marine Shale.
- We purchased an additional 47,500 net acres in the Tuscaloosa Marine Shale resulting in a net acreage position of 132,300 net acres.

Results of Operations

For the three months ended June 30, 2012, we reported a net loss applicable to common stock of $4.7 million, or $0.13 per basic and diluted share, on total revenue of $41.3 million as compared to a net loss applicable to common stock of $1.4 million, or $0.04 per basic and diluted share, on total revenue of $52.9 million for the three months ended June 30, 2011. The decrease in average realized sales price contributed approximately $0.9 million to the decrease in oil and natural gas revenue, while the decrease in production volumes contributed approximately $10.1 million to the decrease in oil and natural gas revenue as compared to the three months ended June 30, 2011. We recorded a $24.0 million gain on derivatives not designated as hedges in the three months ended June 30, 2012, compared to an $11.0 million gain on derivatives not designated as hedges for the three months ended June 30, 2011.

For the six months ended June 30, 2012, we reported a net loss applicable to common stock of $24.0 million, or $0.66 per basic and diluted share, on total revenue of $86.7 million as compared to a net loss applicable to common stock of $26.1 million, or $0.72 per basic and diluted share, on total revenue of $94.1 million for the six months ended June 30, 2011. The decrease in production volumes in the six months ended June 30, 2012 compared to the same period in 2011 reduced oil and natural gas revenue by $11.9 million, while the increase in average realized sales price benefited oil and natural gas revenues in the six months ended June 30, 2012 by approximately $5.3 million. We recorded a $33.5 million gain on derivatives not designated as hedges in the six months ended June 30, 2012, compared to a $0.9 million gain on derivatives not designated as hedges for the six months ended June 30, 2011.

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The following table reflects our summary operating information for the periods presented (in thousands except for price and volume data).

	Three Months Ended June 30,				Six Months Ended June 30,			
(In thousands, except for price data)	2012	2011	Variance		2012	2011	Variance	
Revenues:								
Natural gas	$ 16,279	$ 39,347	$ (23,068)	(59%)	$ 38,623	$ 72,990	$ (34,367)	(47%)
Oil and condensate	25,132	13,087	12,045	92%	48,165	20,362	27,803	137%
Natural gas, oil and condensate	41,411	52,434	(11,023)	(21%)	86,788	93,352	(6,564)	(7%)
Operating revenues	41,346	52,871	(11,525)	(22%)	86,654	94,102	(7,448)	(8%)
Operating expenses	55,503	50,791	4,712	9%	115,052	94,419	20,633	22%
Operating income (loss)	(14,157)	2,080	(16,237)	(781%)	(28,398)	(317)	(28,081)	(8,858%)
Net income (loss) applicable to common stock	(4,714)	(1,430)	(3,284)	(230%)	(23,955)	(26,110)	2,155	8%
Net Production:								
Natural gas (MMcf)	6,758	9,501	(2,743)	(29%)	14,224	18,094	(3,870)	(21%)
Oil and condensate (MBbls)	254	134	120	90%	471	215	256	119%
Total (Mmcfe)	8,282	10,307	(2,025)	(20%)	17,047	19,382	(2,335)	(12%)
Average daily production (Mcfe/d)	91,006	113,268	(22,262)	(20%)	93,665	107,085	(13,420)	(13%)
Average realized sales price per unit:								
Natural gas (per Mcf)	$ 2.41	$ 4.14	$ (1.73)	(42%)	$ 2.72	$ 4.03	$ (1.31)	(33%)
Oil and condensate (per Bbl)	98.96	97.36	1.60	2%	102.36	94.85	7.51	8%
Average realized price (per Mcfe)	5.00	5.09	(0.09)	(2%)	5.09	4.82	0.27	6%

Oil and Natural Gas Revenue

Revenues from operations decreased for the three months ended June, 2012 compared to the same period in 2011 as a result of a 2% net decrease in average realized sales price, and a 20% decrease in daily production. The production decrease in the three month period ended June 30, 2012 compared to the same period in 2011 was caused by a natural decline in natural gas production. In response to depressed natural gas prices, we continue to focus our resources on increasing oil production, which we are currently able to sell at a more favorable relative price. For the three months ended June 30, 2012, 61% of our oil and natural gas revenue was attributable to oil revenue versus 25% for the three months ended June 30, 2011.

Revenues from operations decreased for the six months ended June 30, 2012 compared to the same period in 2011 as a result of a 13% decrease in daily production, partially offset by a 6% net increase in average realized sales price. The production decrease in the six month period ended June 30, 2012 compared to the same period in 2011 was caused by a natural decline in natural gas production. In response to depressed natural gas prices, we continue to focus our resources on increasing oil production, which we are currently able to sell at a more favorable relative price. For the six months ended June 30, 2012, 55% of our oil and natural gas revenue was attributable to oil revenue versus 22% for the six months ended June 30, 2011.

For the three months ended June 30, 2012, our average realized price for natural gas was $2.41 per Mcf, excluding the effect of the realized gains on our natural gas derivatives. For the same period in 2011, our average realized price for natural gas was $4.14 per Mcf, excluding the realized gains on our natural gas derivatives. For the three months ended June 30, 2012, our average realized price for natural gas was $5.26 per Mcf, including the effect of the realized gains on our natural gas derivatives. For the same period in 2011, our average realized price for natural gas was $4.77 per Mcf, including the effect of the realized gains on our natural gas derivatives.

For the six months ended June 30, 2012, our average realized price for natural gas was $2.72 per Mcf, excluding the effect of the realized gains on our natural gas derivatives. For the same period in 2011, our average realized price for natural gas was $4.03 per Mcf, excluding the realized gains on our natural gas derivatives. For the six months ended June 30, 2012, our average realized price for natural gas was $5.22 per Mcf, including the effect of the realized gains on our natural gas derivatives. For the same period in 2011, our average realized price for natural gas was $4.74 per Mcf, including the effect of the realized gains on our natural gas derivatives.

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For the three months ended June 30, 2012, our average realized price for oil was $98.96 per Bbl, excluding the effect of the realized gains on our oil derivatives. For the same period in 2011, our average realized price for oil was $97.36 per Bbl, excluding the effect of the realized losses on our oil derivatives. For the three months ended June 30, 2012, our average realized price for oil including the effect of realized gains on our oil derivatives was $107.15 per Bbl. For the same period in 2011, our average realized price for oil was $97.26 per Bbl, including the effect of the realized losses on our oil derivatives.

For the six months ended June 30, 2012, our average realized price for oil was $102.36 per Bbl, excluding the effect of the realized gains on our oil derivatives. For the same period in 2011, our average realized price for oil was $94.85 per Bbl, excluding the effect of the realized gains on our oil derivatives. For the six months ended June 30, 2012, our average realized price for oil including the effect of the realized gains on our oil derivatives was $105.63 per Bbl. For the same period in 2011, our average realized price for oil was $96.71 per Bbl, including the effect of the realized gains on our oil derivatives.

The difference between our average realized prices inclusive of the effect of the realized gains and losses on our oil and natural gas derivatives in the three and six months ended June 30, 2012 and 2011 periods relates to our new natural gas and oil swap contracts. As of June 30, 2012, we have 60,000 MMBtu per day hedged at an average floor price of $5.78 per MMBtu, and as of June 30, 2011, we had 40,000 MMBtu per day hedged at an average floor price of $6.00 per MMbtu. As of June 30, 2012, we have 3,000 Bbls per day hedged at an average fixed price of $101.18 per MMBtu, and as of June 30, 2011, we had 1,000 Bbls per day hedged at an average fixed price of $102.40 per Bbl.

Operating Expenses

Operating expenses increased $4.7 million, or 9%, to $55.5 million in three months ended June 30, 2012 from $50.8 million in the same period in 2011. This increase is caused by increased lease operating expenses, transportation and processing and depreciation, depletion and amortization (DD&A) expense.

Operating expenses increased $20.7 million, or 22%, to $115.1 million in six months ended June 30, 2012 from $94.4 million in the same period in 2011. This increase is caused by increased lease operating expenses, transportation and processing and depreciation, depletion and amortization (DD&A) expense.

	Three Months Ended June 30,				**Six Months Ended June 30,**			
Operating Expenses (in thousands)	**2012**	**2011**	**Variance**		**2012**	**2011**	**Variance**	
Lease operating expenses	$ 6,695	$ 5,215	$ 1,480	28%	$ 15,049	$ 10,118	$ 4,931	49%
Production and other taxes	2,087	1,645	442	27%	4,080	2,595	1,485	57%
Transportation and processing	3,522	2,301	1,221	53%	7,650	4,687	2,963	63%
Exploration	2,019	2,325	(306)	(13%)	4,232	4,741	(509)	(11%)

	Three Months Ended June 30,				**Six Months Ended June 30,**			
Operating Expenses per Mcfe	**2012**	**2011**	**Variance**		**2012**	**2011**	**Variance**	
Lease operating expenses	$ 0.81	$ 0.51	$ 0.30	59%	$ 0.88	$ 0.52	$ 0.36	69%
Production and other taxes	0.25	0.16	0.09	56%	0.24	0.13	0.11	85%
Transportation and processing	0.43	0.22	0.21	95%	0.45	0.24	0.21	88%
Exploration	0.24	0.23	0.01	4%	0.25	0.24	0.01	4%

Lease Operating Expense

Lease operating expense (LOE) for the three months ended June 30, 2012, increased in comparison to the same period in 2011. LOE during the current period included an expense of $0.7 million in workover costs which added $0.08 per Mcfe to unit expense. Our LOE is trending higher as we add more oil wells which carry higher operating costs than natural gas wells. Oil contributed 18% to our production volumes in the second quarter 2012 compared to only 8% in second quarter 2011.

LOE for the six months ended June 30, 2012, increased in comparison to the same period in 2011. LOE during the current period included an expense of $3.0 million in workover costs which added $0.17 per Mcfe to unit expense. Our LOE is trending higher as we add more oil wells to our well count which carry higher operating costs than natural gas wells. Oil contributed 17% to our production volumes in the first half of 2012 compared to only 7% in the first half of 2011.

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Production and Other Taxes

Production and other taxes for the three months ended June 30, 2012 include production tax of $1.6 million and ad valorem tax of $0.5 million. Production tax for the current period is net of $0.2 million of tax credits attributed to Tight Gas Sands (TGS) credits for our natural gas wells in the State of Texas. During the comparable period in 2011, production and other taxes included production tax of $0.9 million and ad valorem tax of $0.7 million. Production tax for that comparable period was net of $0.4 million in TGS credits.

Production and other taxes for the six months ended June 30, 2012 include production tax of $3.3 million and ad valorem tax of $0.8 million. Production tax for the current period is net of $0.4 million of tax credits attributed to TGS credits for our natural gas wells in the State of Texas. During the comparable period in 2011, production and other taxes included production tax of $1.3 million and ad valorem tax of $1.3 million. Production tax for that comparable period was net of $0.9 million in TGS credits.

The increase in production and other taxes in 2012 over 2011 is attributable to production taxes incurred in connection with our new Texas oil wells that are not subject to any production tax abatement.

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

Our Louisiana horizontal wells are eligible for a two year severance tax exemption from the date of first production or until payout of qualified costs, whichever comes first. Many of our exempt Louisiana wells are reaching the two year maturity and, as a result, we incurred higher production taxes compared to first half of 2011.

Transportation and Processing Expense

Transportation and processing expense increased in the three and six months ended June 30, 2012 compared to the same period in 2011, partially as a result of higher gathering costs related to our gas production from the Eagle Ford Shale Trend wells but more predominately related to the renegotiation of certain natural gas gathering and processing contracts. In return for paying higher gathering and processing fees we are receiving higher pricing due to the existence of natural gas liquids in our natural gas thereby increasing our revenues.

Exploration

The decrease in exploration expense for the three months ended June 30, 2012 compared to the same period in 2011 is attributed to 2011 including $0.6 million for seismic costs partially offset by 2012 including $0.3 million for delay rental expense.

The decrease in exploration expense for the six months ended June 30, 2012 compared to the same period in 2011 relates to $0.6 million of seismic costs in 2011, a $0.4 million decrease in leasehold cost amortization partially offset by $0.3 million in delay rental expense in 2012 and a $0.2 million increase in exploration labor cost.

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses (in thousands)	**2012**	**2011**	**Variance**		**2012**	**2011**	**Variance**	
Depreciation, depletion and amortization	$ 34,562	$ 30,927	$ 3,635	12%	$ 66,840	$ 55,886	$ 10,954	20%
Impairment		1,050	(1,050)	(100%)	2,662	1,050	1,612	154%
General and administrative	6,690	7,328	(638)	(9%)	14,611	15,578	(967)	(6%)
Gain on sale of assets	(72)		(72)	(100%)	(72)	(236)	164	69%

	Three Months Ended June 30,				Six Months Ended June 30,			
Operating Expenses per Mcfe	**2012**	**2011**	**Variance**		**2012**	**2011**	**Variance**	
Depreciation, depletion and amortization	$ 4.17	$ 3.00	$ 1.17	39%	$ 3.92	$ 2.88	$1.04	36%
Impairment		0.10	(0.10)	(100%)	0.16	0.05	0.11	220%
General and administrative	0.81	0.71	0.10	14%	0.86	0.80	0.06	8%
Gain on sale of assets	(0.01)		(0.01)	(100%)		(0.01)	(0.01)	(100%)

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Depreciation Depletion and Amortization (DD&A)

DD&A expense in the three months ended June 30, 2012 compared to the same period in 2011 is affected by an increase in oil production volumes and a greater percentage of our production volumes coming from operating areas with higher DD&A rates, such as our Eagle Ford Shale Trend oil properties. The average DD&A rate increased 39% while our oil production increased 90% period to period.

DD&A expense in the six months ended June 30, 2012 compared to the same period in 2011 is affected by an increase in oil production volumes and a greater percentage of our production volumes coming from operating areas with higher DD&A rates, such as our Eagle Ford Shale Trend oil properties. The average DD&A rate increased 36% while our oil production increased 119% period to period.

Impairment

We recorded impairment expense of $2.7 million in the first quarter of 2012. The majority is related to our non-core fields due to declining natural gas prices. We recorded no impairment in the second quarter of 2012 compared to the $1.0 million impairment recorded in the second quarter of 2011 attributed to an asset retirement obligation on one field.

General and Administrative (G&A) Expense

G&A expense decreased in the three months ended June 30, 2012 compared to the same period 2011. The decrease reflects lower employee health benefit costs, lower professional service fees and higher overhead recovery from capital projects. Share based compensation expense, which is a non-cash item, amounted to $1.5 million in 2012 compared to $1.3 million in 2011.

G&A expense decreased in the six months ended June 30, 2012 compared to the same period 2011. The decrease reflects lower employee related cost due to lower average head count and higher overhead recovery from capital projects. Share based compensation expense, which is a non-cash item, amounted to $3.0 million in 2012 compared to $3.2 million in 2011.

Gain on Sale of Assets

We recorded a gain of $0.1 million on the sale of one non-core well in the six months ended June 30, 2012. We recorded a gain of $0.2 million on the sale on non-core oil and natural gas properties in the six months ended June 30, 2011.

Other Income (Expense)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Other income (expense) (in thousands):				
Interest expense	$ (13,089)	$ (12,965)	$ (26,002)	$ (23,793)
Interest income and other	1	10	1	22
Gain on derivatives not designated as hedges	24,043	10,954	33,468	944
Gain on extinguishment of debt		3		58
Average funded borrowings adjusted for debt discount	622,609	494,670	600,480	448,761
Average funded borrowings	635,765	531,867	618,342	489,347

Interest Expense

The increase in interest expense for the three months ended June 30, 2012 compared to the three months ended June 30, 2011 was primarily caused by our higher average level of outstanding debt in the three months ended June 30, 2012. The higher average level of debt resulted from borrowings on our Senior Credit Facility. Non-cash interest of $3.1 million is included in the $13.1 million interest expense reported for the three months ended June 30, 2012.

The increase in interest expense for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 was primarily caused by our higher average level of outstanding debt in the six months ended June 30, 2012. The higher average level of debt resulted from increased borrowings under our Senior Credit Facility and the refinancing of almost all of the $175 million of our 3.25% Convertible Senior Notes due

2026 (the 2026 Notes) with proceeds from the offering of $275 million of our 8.875% Senior Notes due 2019 (the 2019 Notes). Non-cash interest of $6.3 million is included in the $26.0 million interest expense reported for the six months ended June 30, 2012.

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Gain on Derivatives Not Designated as Hedges

Gain on derivatives not designated as hedges for the three months ended June 30, 2012 includes a realized gain of $21.3 million and an unrealized gain of $2.7 million for the change in the fair value of our oil and natural gas derivative contracts. Gain on oil derivatives was $27.0 million for the three months ended June 30, 2012 consisting of a realized gain of $2.1 million and an unrealized gain of $24.9 million reflecting the fall in oil futures prices for the period. Loss on natural gas derivatives for the three months ended June 30, 2012 was $3 million, consisting of a realized gain of $19.2 million offset by an unrealized loss of $22.2 million. The unrealized loss was the result of the roll off of settled contracts and natural gas futures price improvements.

Gain on derivatives not designated as hedges for the three months ended June 30, 2011, consists of a realized gain of $6.0 million and an unrealized gain of $5.0 million for the change in fair value of our oil and natural gas derivative contracts. The average futures strip prices for oil and natural gas trended lower in the prior year period resulting in the unrealized gain.

Gain on derivatives not designated as hedges for the six months ended June 30, 2012 includes a realized gain of $37.2 million, partially offset by an unrealized loss of $3.8 million for the change in the fair value of our oil and natural gas derivative contracts. Gain on oil derivatives was $21.1 million for the six months ended June 30, 2012 consisting of a realized gain of $1.5 million and an unrealized gain of $19.6 million reflecting the fall in oil futures prices for the period. Gain on natural gas derivatives for the six months ended June 30, 2012 was $12.4 million, consisting of a realized gain of $35.7 million offset by an unrealized loss of $23.3 million. The unrealized loss was the result of the roll off of settled contracts and natural gas futures price improvements.

Gain on derivatives not designated as hedges for the six months ended June 30, 2011, consists of a realized gain of $13.1 million offset by an unrealized loss of $12.2 million for the change in fair value of our oil and natural gas derivative contracts. The average futures strip prices for oil trended higher in the prior year period resulting in the unrealized loss. The unrealized loss in natural gas derivative contracts was the result of the roll off of settled contracts.

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

Income Tax Benefit

We recorded no income tax benefit for the three and six months ended June 30, 2012. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of June 30, 2012.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity during the first six months of 2012 were from cash on hand, cash flow from operating activities and borrowings under our Senior Credit Facility. We used cash primarily to fund our capital spending program, pay interest on outstanding debt and pay preferred stock dividends. We expect to finance our estimated capital expenditures for the remainder of 2012 through a combination of cash from operating activities and borrowings under our Senior Credit Facility.

Our total 2012 capital expenditure budget is $250 million. We have changed our capital expenditure allocation and expect capital spending by area to be approximately 70% for Eagle Ford Shale Trend, 11% for Haynesville Shale Trend, 8% for the Tuscaloosa Marine Shale and 11% for leasehold and infrastructure.

We have in place a $600 million Senior Credit Facility, entered into with a syndicate of U.S. and international lenders. As of June 30, 2012, we had a $265 million borrowing base with $158 million outstanding. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The Fourth Amendment became effective upon the closing of the issuance and sale of our 2019 Notes, which occurred on March 2, 2011, and the placement of $175 million of net proceeds in an escrow account which was used for the redemption of $174.6 million of our 2026 Notes. We were in compliance with existing covenants under the Senior Credit Facility at June 30, 2012.

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

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Alternatives available to us include:

- sale of non-core assets;
- joint venture partnerships in our core Haynesville Shale, Eagle Ford Shale Trend and/or Tuscaloosa Marine Shale acreage;
- availability under our Senior Credit Facility; and
- issuance of debt securities.

We have supported our cash flows with oil and natural gas derivative contracts which covered approximately 81% of our oil and natural gas sales volumes for the first six months of 2012. We have also supported our cash flows by entering into derivative positions currently covering approximately 61% of our projected oil and 78% of our projected natural gas sales volumes for the remainder of 2012. See *Note 7 - Derivative Activities in the Notes to Consolidated Financial Statements under Part 1 Item 1 of this Form 10-Q.*

Cash Flows

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

	Six Months Ended June 30,		
	2012	**2011**	**Variance**
Cash flow statement information:			
Net cash:			
Provided by operating activities	$ 77,930	$ 67,921	$ 10,009
Used in investing activities	(131,738)	(193,336)	61,598
Provided by financing activities	52,416	108,174	(55,758)
Decrease in cash and cash equivalents	$ (1,392)	$ (17,241)	$ (15,849)

Operating activities. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided by operating activities increased $10.0 million for the six months ended June 30, 2012 compared to the same period in 2011. Cash received related to oil and natural gas revenue increased $6.3 million in the six months ended June 30, 2012 compared to the same period in 2011 due to (i) growth in oil volumes as a percentage of total volumes from 7% in 2011 to 17% in 2012, and (ii) a 6% increase in the average realized sales price from $4.82 to $5.09 per Mcfe. Also additive to cash flow from operations was $24.1 million in additional realized cash settlements on our derivative contracts. Offsetting decreases to cash flow in the six months ended June 30, 2012 include (i) operating costs increased $7.7 million in 2012 as compared to 2011 (ii) $4.1 million in additional cash interest paid in 2012 as we refinanced $175 million of our 2026 Notes with $275 million of our 2019 Notes and increased borrowings under our Senior Credit Facility and (iii) $8.4 million in working capital changes.

Investing activities. Net cash used in investing activities was $131.8 million for the six months ended June 30, 2012, compared to $193.3 million for 2011. While we booked capital expenditures of approximately $136.1 million in the six months ended June 30, 2012, we paid out cash amounts totaling $131.8 million in the six months ended June 30, 2012, with the difference being attributed to $26.3 million in drilling and completion costs accrued at June 30, 2012 and non-cash asset retirement obligation additions of $0.3 million, partially offset by $22.3 million in drilling and completion cost accrued at December 31, 2011 and paid in the six months ended June 30, 2012.

Financing activities. The net cash provided by financing activities for six months ended June 30, 2012 consisted primarily of proceeds from net borrowings under our Senior Credit Facility of $55.5 million, partially offset by preferred stock dividends of $3.0 million. We have $158.0 million borrowings outstanding under our Senior Credit Facility as of June 30, 2012. In the six months ended June 30, 2011 net cash provided by financing activities consisted of proceeds from the issuance our 2019 Notes and borrowings under our Senior Credit Facility offset by the redemption of a majority of our 2026 Notes, cash restricted for the repurchase of convertible notes, financing cost on the issuance of 2019 Notes and preferred stock dividend.

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

	June 30, 2012			December 31, 2011		
	Principal	Carrying Amount	Fair Value (1)	Principal	Carrying Amount	Fair Value (1)
Senior Credit Facility	$ 158,000	$ 158,000	$ 158,000	$ 102,500	$ 102,500	$ 102,500
3.25% Convertible Senior Notes due 2026	429	429	429	429	429	429
5.0% Convertible Senior Notes due 2029 (2)	218,500	193,081	203,751	218,500	188,197	201,785
8.875% Senior Notes due 2019	275,000	275,000	271,013	275,000	275,000	243,898
Total debt	$ 651,929	$ 626,510	$ 633,193	$ 596,429	$ 566,126	$ 548,612

(1) The carrying amount for the Senior Credit Facility represents fair value because the variable interest rates are reflective of current market conditions and the carrying amount of the 3.25% Convertible Senior Notes due 2026 represents fair value because the last transacted activity was at par; otherwise, fair value was obtained by direct market quotes within Level 1 of the fair value hierarchy.

(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was $25.4 million and 30.3 million as of June 30, 2012 and December 31, 2011 respectively.

The following table summarizes the total interest expense (contractual interest expense, amortization of debt discount and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

	Three Months Ended June 30, 2012		Three Months Ended June 30, 2011		Six Months Ended June 30, 2012		Six Months Ended June 30, 2011	
	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate
Senior Credit Facility	1,336	3.7%	852		2,496	3.9%	1,711	
3.25% Convertible Senior Notes due 2026	3	3.3%	614	8.9%	7	3.3%	3,397	9.2%
5.0% Convertible Senior Notes due 2029	5,423	11.3%	5,175	11.4%	10,846	11.4%	10,350	11.5%
8.875% Senior Notes due 2019	6,327	9.2%	6,324	9.2%	12,653	9.2%	8,327	9.2%

* An Effective Interest Rate Calculation is not meaningful for the three and six months ended June 30, 2011 since there were only minimal to no amounts borrowed under the Senior Credit Facility during the period.

For additional information on our financing activities, see *Note 3 Debt in the Notes to Consolidated Financial Statements under Part 1 Item I of this Form 10-Q*.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements which were prepared in accordance with generally accepted accounting principles in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We believe that certain accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements. Our Annual Report on Form 10-K for the year ended December 31, 2011, includes a discussion of our critical accounting policies and there have been no material changes to such policies during the six months ended June 30, 2012.

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Item 3 Quantitative and Qualitative Disclosures about Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. Our risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments we utilize include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments we utilize may vary from year to year and is governed by risk-management policies with levels of authority delegated by our Board of Directors. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and we may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding our accounting policies and additional information related to our derivative and financial instruments, see Note 1 Description of Business and Significant Accounting Policies , Note 7 Derivative Activities and Note 3 Debt in the Notes to Consolidated Financial Statements under Part 1 Item I of this Quarterly Report on Form 10-Q.

Commodity Price Risk

Our most significant market risk relates to fluctuations in natural gas and crude oil prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. In addition, a non-cash write-down of our oil and natural gas properties may be required if future commodity prices experience a sustained and significant decline. Below is a sensitivity analysis of our commodity-price-related derivative instruments.

As of June 30, 2012, we have derivative instruments in place for 2012 of approximately 60,000 Mbtu per day (natural gas) and 3,000 Bbls per day (crude oil). At June 30, 2012, we have a net asset derivative position of $35.3 million related to these derivative instruments. Utilizing actual derivative contractual volumes a hypothetical 10% increase in oil and natural gas prices would have decreased the net derivative asset to $22.2 million, while a hypothetical 10% decrease in oil and natural gas prices would have increased the net derivative asset to $49.4 million. However, a gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Adoption of Comprehensive Financial Reform

The adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Risk Factors in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

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Item 4 Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of June 30, 2012, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

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

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PART II OTHER INFORMATION

Item 1 Legal Proceedings

A discussion of current legal proceedings is set forth in Part I, Item 1. Financial Statements, under Note 8 Commitments and Contingencies to our consolidated financial statements in this Form 10-Q.

Item 1A Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially affect our business, financial condition or future results.

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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.
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*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document
*101.LAB	XBRL Labels Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document

* Filed herewith
** Furnished herewith

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SIGNATURES

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

GOODRICH PETROLEUM CORPORATION

(Registrant)

Date: August 7, 2012	By:	/S/ Walter G. Goodrich **Walter G. Goodrich** **Vice Chairman & Chief Executive Officer**
Date: August 7, 2012	By:	/S/ Jan L. Schott **Jan L. Schott** **Senior Vice President & Chief Financial Officer**

GOODRICH PETROLEUM CORPORATION LIST OF EXHIBITS TO FORM 10-Q

FOR QUARTER ENDED JUNE 30, 2012

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