

CARRIZO OIL & GAS INC
Form 10-Q
August 08, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____
Commission File Number 000-29187-87

CARRIZO OIL & GAS, INC.
(Exact name of registrant as specified in its charter)

Texas 76-0415919
(State or other jurisdiction of (IRS Employer
incorporation or organization) Identification No.)

500 Dallas Street, Suite 2300, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)
(713) 328-1000
(Registrant's telephone number)

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 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES NO

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

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Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES NO

The number of shares outstanding of the registrant's common stock, par value \$0.01 per share, as of July 31, 2012 was 39,977,522.

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 FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2012
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PART I. FINANCIAL INFORMATION
Item 1. Consolidated Financial Statements
CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

	June 30, 2012 (Unaudited)	December 31, 2011
	(In thousands, except per share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 20,769	\$ 28,112
Accounts receivable, net		
Oil and gas sales	27,235	21,988
Joint interest billing	55,059	31,050
Related party	1,463	—
Other	2,659	1,740
Advances to operators	528	97
Fair value of derivative instruments	34,829	27,877
Prepays and other current assets	5,605	9,533
Total current assets	148,147	120,397
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full cost method of accounting		
Proved oil and gas properties, net	961,605	842,041
Unproved properties and significant development projects, not being amortized	491,098	459,735
Other property and equipment, net	11,444	8,738
TOTAL PROPERTY AND EQUIPMENT, NET	1,464,147	1,310,514
DEFERRED FINANCING COSTS, NET	21,345	23,217
INVESTMENT	2,523	2,523
FAIR VALUE OF DERIVATIVE INSTRUMENTS	24,441	9,617
DEFERRED INCOME TAXES	42,340	59,755
OTHER ASSETS	1,699	1,657
TOTAL ASSETS	\$ 1,704,642	\$ 1,527,680
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	\$ 73,393	\$ 25,672
Revenue and royalties payable	75,355	54,600
Current taxes payable	460	1,048
Accrued drilling costs	77,333	92,179
Accrued interest	11,891	12,059
Other accrued liabilities	25,133	21,414
Advances for joint operations	20,837	54,179
Current maturities of long-term debt	16,650	—
Deferred income taxes	11,098	9,685
Other current liabilities	2,552	484
Total current liabilities	314,702	271,320
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT	816,478	729,300
ASSET RETIREMENT OBLIGATIONS	11,563	11,242

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FAIR VALUE OF DERIVATIVE INSTRUMENTS	103	9
OTHER LIABILITIES	4,496	5,954
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Common stock, \$0.01 par value (90,000 shares authorized, 39,978 and 39,563 shares issued and outstanding at June 30, 2012 and December 31, 2011, respectively)	400	395
Additional paid-in capital	656,942	647,429
Accumulated deficit	(100,042) (137,969
Total shareholders' equity	557,300	509,855
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 1,704,642	\$ 1,527,680

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For The Three Months Ended June 30,		For The Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands, except per share amounts)			
OIL AND GAS REVENUES	\$83,818	\$50,672	\$164,533	\$94,730
COSTS AND EXPENSES				
Lease operating	7,031	7,427	15,454	14,093
Production tax	3,128	1,466	6,227	2,407
Ad valorem tax	2,296	981	5,911	1,672
Depreciation, depletion and amortization	43,380	20,595	74,941	37,271
General and administrative (inclusive of stock-based compensation expense of \$1,516 and \$6,805 for the three months ended June 30, 2012 and 2011, respectively, and \$5,532 and \$10,655 for the six months ended June 30, 2012 and 2011, respectively)	13,094	14,094	24,632	23,339
Accretion related to asset retirement obligations	170	71	348	145
TOTAL COSTS AND EXPENSES	69,099	44,634	127,513	78,927
OPERATING INCOME	14,719	6,038	37,020	15,803
OTHER INCOME AND EXPENSES				
Gain (loss) on derivative instruments, net	38,247	12,065	41,285	11,878
Loss on extinguishment of debt	—	—	—	(897)
Interest expense	(17,686)	(12,407)	(35,022)	(24,615)
Capitalized interest	7,809	5,649	13,832	10,909
Other income (expense), net	225	(1)	(360)	61
INCOME BEFORE INCOME TAXES	43,314	11,344	56,755	13,139
INCOME TAX EXPENSE	(14,810)	(3,602)	(18,828)	(4,662)
NET INCOME	\$28,504	\$7,742	\$37,927	\$8,477
NET INCOME PER COMMON SHARE				
Basic	\$0.72	\$0.20	\$0.96	\$0.22
Diluted	\$0.71	\$0.20	\$0.95	\$0.21
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				
Basic	39,596	38,898	39,520	38,841
Diluted	40,042	39,497	39,987	39,450

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For The Six Months Ended June 30,		
	2012	2011	
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	\$37,927	\$8,477	
Adjustments to reconcile net income to net cash provided by operating activities-			
Depreciation, depletion and amortization	74,941	37,271	
Unrealized (gain) loss on derivative instruments, net	(20,265) 3,032	
Accretion related to asset retirement obligations	348	145	
Loss on extinguishment of debt	—	897	
Stock-based compensation, net of amounts capitalized	5,532	10,655	
Allowance for doubtful accounts	41	(54)
Deferred income taxes	18,828	4,739	
Amortization of debt discount and deferred financing costs, net of amounts capitalized	2,091	1,570	
Other, net	2,387	4,058	
Changes in operating assets and liabilities-			
Accounts receivable	(31,279) (2,912)
Accounts payable	50,896	8,381	
Accrued liabilities	6,244	3,876	
Other, net	(2,592) (6,013)
Net cash provided by operating activities	145,099	74,122	
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(409,027) (219,179)
Increase in capital expenditure payables and accruals	823	12,464	
Proceeds from sales of oil and gas properties, net	190,892	101,590	
Advances to operators	(431) (138)
Advances for joint operations	(33,342) 12,368	
Other, net	(2,655) (221)
Net cash used in investing activities	(253,740) (93,116)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings and issuances	539,540	346,000	
Debt repayments	(438,000) (298,660)
Payments of debt issuance and retirement costs	(248) (8,419)
Proceeds from stock options exercised	6	47	
Net cash provided by financing activities	101,298	38,968	
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(7,343) 19,974	
CASH AND CASH EQUIVALENTS, beginning of period	28,112	4,128	
CASH AND CASH EQUIVALENTS, end of period	\$20,769	\$24,102	

The accompanying notes are an integral part of these consolidated financial statements.

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CARRIZO OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, the "Company"), is actively engaged in the exploration, development, and production of oil and gas in the United States (the "U.S.") and United Kingdom (the "U.K."). The Company's current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Niobrara Formation in Colorado, the Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania and West Virginia, and the U.K. North Sea where the Huntington Field project is currently under development.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles ("GAAP"). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. The consolidated financial statements reflect all necessary adjustments, all of which were of a normal recurring nature and are in the opinion of management necessary for a fair presentation of the Company's interim financial position, results of operations and cash flows. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"). The operating results for the three and six months ended June 30, 2012 are not necessarily indicative of the results to be expected for the full year. The consolidated financial statements included herein should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, shareholders' equity, net income, or net cash provided by/used in operating, investing or financing activities.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves which are used in calculating the amortization of proved oil and gas property costs, the present value of future net revenues included in the full cost ceiling tests, estimates of future taxable income used in assessing the realizability of deferred tax assets, and asset retirement obligations. Other significant estimates include the impairment of unproved properties, fair values of derivative instruments, stock-based compensation, the collectability of outstanding receivables, and contingencies. Proved oil and gas reserve estimates have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality and quantity of available data and the application of engineering and geological interpretation and judgment to available data. Subsequent drilling results, testing and production may justify revisions of such estimates. Accordingly, proved oil and gas reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, proved oil and gas reserve estimates are vulnerable to changes in average market prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices of oil and gas, the creditworthiness of counterparties, interest rates and the market value and volatility of the Company's common stock. Future changes in these assumptions may affect these significant estimates materially in the near term.

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Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts

The Company establishes an allowance for doubtful accounts when it determines that it will not collect all or a part of an accounts receivable balance. The Company assesses the collectability of its accounts receivable on a quarterly basis and adjusts the allowance as necessary using the specific identification method. At June 30, 2012 and December 31, 2011, the Company's allowance for doubtful accounts was \$1.9 million and \$2.3 million, respectively.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from oil and gas sales, joint interest billings to working interest owners in the oil and gas industry or drilling and completion advances to third-party operators for development costs of wells in progress. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not require collateral from its customers. The Company generally has the right to offset revenue against related billings to joint interest owners.

Derivative instruments subject the Company to a concentration of credit risk. See Note 8. Derivative Instruments for further discussion of concentration of credit risk related to the Company's derivative instruments.

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to costs centers established on a country-by-country basis. Internal costs, including payroll and stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized and totaled \$4.1 million and \$3.1 million for the three months ended June 30, 2012 and 2011, respectively, and \$7.5 million and \$5.5 million for the six months ended June 30, 2012 and 2011, respectively. Internal costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting oil and natural gas liquids to gas equivalents at the ratio of one barrel of oil or natural gas liquids to six thousand cubic feet of gas, which represents their approximate relative energy content. The equivalent unit-of-production rate is computed on a quarterly basis by dividing production by proved oil and gas reserves at the beginning of the quarter then applying such amount to capitalized oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average depreciation, depletion and amortization ("DD&A") per Mcfe on oil and gas properties was \$3.02 (\$18.12 per Boe) and \$1.84 (\$11.04 per Boe) for the three months ended June 30, 2012 and 2011, respectively, and \$2.66 (\$15.96 per Boe) and \$1.70 (\$10.20 per Boe) for the six months ended June 30, 2012 and 2011, respectively.

Unproved properties and significant development projects, not being amortized include unevaluated leasehold and seismic costs associated with specific unevaluated properties, significant development projects in cost centers with no production and on which exploration or development activities are in progress, related capitalized interest and the cost of exploratory wells in progress. Significant costs of unevaluated properties and exploratory wells in progress are assessed individually on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs are added to the oil and gas property costs subject to amortization. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling capital expenditure plans. The Company expects to complete its evaluation of the majority of its unevaluated leasehold and seismic costs within the next two to five years and exploratory wells in progress within the next year. Individually insignificant costs of unevaluated properties are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. The Company capitalized interest costs associated with its unevaluated leasehold and seismic costs and significant development projects, not being amortized of \$7.8 million and \$5.6 million for the three months ended June 30, 2012 and 2011, respectively, and \$13.8 million and \$10.9 million for the six months ended June 30, 2012 and 2011, respectively. Interest is capitalized

on the average balance of unevaluated leasehold and seismic costs or the capitalized oil and gas property costs of significant development projects, not being amortized using a weighted-average interest rate based on outstanding borrowings of the relevant cost center.

Proceeds from the sale of oil and gas properties are recognized as a reduction of capitalized oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company has not had any sales of oil and gas properties that significantly alter that relationship.

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In connection with the formation of ACP II Marcellus LLC (“ACP II”), the Company’s partner in one of its joint ventures in the Marcellus Shale, the Company was issued a class of interests (“B Units”) in ACP II. The B Units entitle the Company to certain percentages of cash distributions to affiliates of Avista Capital Partners, LP, (together with its affiliates, “Avista”), if, when and only to the extent that those cash distributions exceed certain internal rates-of-return and return-on-investment thresholds with respect to Avista’s investment in ACP II as set forth in the limited liability company agreement of ACP II, as amended, unless and until we increase our interest in certain oil and gas properties of ACP II located in Pennsylvania and Ohio or sell substantially all of our interest in such properties. Because the B Units do not provide the Company with an ownership interest in the oil and gas properties of ACP II, the Company is not required to pay for property acquisition, exploration or development costs associated with ACP II’s ownership interest in oil and gas properties, nor do the B Units entitle the Company to recognize oil and gas production and therefore, proved reserves associated with ACP II’s ownership interest in oil and gas properties. However, under the full cost method of accounting, cash distributions received on the B Units are considered proceeds from the sale of oil and gas properties which are recognized as a reduction of capitalized oil and gas property costs.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the “cost center ceiling” equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of properties not subject to amortization, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the ceiling test are calculated using average quoted market prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices used in the ceiling test computation do not include the impact of derivative instruments because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from five to ten years.

Deferred Financing Costs

Deferred financing costs include legal fees, accounting fees, underwriting fees, printing costs, and other direct costs associated with revolving credit facilities or the issuance of debt securities. The capitalized costs are amortized to interest expense, net of amounts capitalized using the effective interest method over the terms of the debt securities or revolving credit facilities.

Investment

The Company accounts for its investment in Oxane Materials, Inc. (“Oxane”) using the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from Oxane.

Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, receivables, payables, derivative instruments and debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of derivative instruments are based on a pricing model that uses market data obtained from reputable independent sources, including (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The carrying amounts of debt under the Revolving Credit Facility and the Huntington Facility (as defined in Note 5. Debt below) approximate fair value as these borrowings bear interest at variable rates of interest. The carrying amounts of the Company’s 8.625% Senior Notes due 2018, or the Senior Notes, and its 4.375% Convertible Senior Notes due 2028, or the Convertible Senior Notes, may not approximate fair value because the notes bear interest at fixed rates of interest. See Note 5. Debt and Note 9. Fair Value Measurements.

Asset Retirement Obligations

The Company's oil and gas properties require expenditures to plug and abandon wells after the reserves have been depleted. The asset retirement obligation is recognized as a liability at its fair value when the well is drilled with an associated increase in oil and gas property costs. Asset retirement obligations require estimates of the costs to plug and abandon wells, the costs to restore the surface, the remaining lives of wells based on oil and gas reserve estimates and future inflation rates. The obligations are discounted using a credit-adjusted risk-free interest rate which is accreted over the estimated productive lives of the oil and

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gas properties to their expected settlement values. Estimated costs consider historical experience, third party estimates and state regulatory requirements and do not consider salvage values. At least annually, the Company reassesses its asset retirement obligations to determine whether a change in the estimated obligation is necessary. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in estimated costs to plug and abandon wells and changes in estimated timing of oil and gas property retirement. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement, which is included in oil and gas property costs. On an interim basis, the Company reassesses the estimated cash flows underlying the obligation when indicators suggest the estimated cash flows underlying the obligation have materially changed and updates its estimated obligation if necessary.

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable.

Revenue Recognition

Oil and gas revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. The Company follows the sales method of accounting for oil and gas revenues whereby revenue is recognized for all oil and gas sold to purchasers, regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as an asset or liability to the extent that the Company has an imbalance on a specific property that is in excess of its remaining proved oil and gas reserves. Oil and gas sales volumes are not significantly different from the Company's share of production, and as of June 30, 2012 and December 31, 2011, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage commodity price risk associated with a portion of its forecasted oil and gas production. Derivative instruments are recognized at their balance sheet date fair value as assets or liabilities in the consolidated balance sheets. Although the derivative instruments provide an economic hedge of the Company's exposure to commodity price risk associated with a portion of its forecasted oil and gas production, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, unrealized gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations. Realized gains and losses as a result of cash settlements with counterparties to the Company's derivative instruments are also recorded as gain (loss) on derivative instruments, net in the consolidated statements of operations. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty and subject to master netting agreements.

The Company's Board of Directors establishes risk management policies and reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades. See Note 8. Derivative Instruments for further discussion of the Company's derivative instruments.

Stock-Based Compensation

The Company grants stock options, stock appreciation rights ("SARs") that may be settled in cash or common stock at the option of the Company ("Stock SARs"), SARs that may only be settled in cash ("Cash SARs"), restricted stock awards and restricted stock units to directors, employees and independent contractors. The Company recognized the following stock-based compensation expense for the periods indicated which is reflected as general and administrative expense in the consolidated statements of operations:

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	Three Months Ended		Six Months Ended	
	June 30, 2012	2011	June 30, 2012	2011
	(In thousands)			
Stock Options and SARs	\$ (2,975)	\$ 4,914	\$ (1,309)	\$ 6,914
Restricted Stock Awards and Units	5,476	3,330	8,581	6,450
	2,501	8,244	7,272	13,364
Less: Amounts Capitalized	(985)	(1,439)	(1,740)	(2,709)
Total Stock-Based Compensation Expense	\$ 1,516	\$ 6,805	\$ 5,532	\$ 10,655
Income Tax Benefit	\$ 562	\$ 2,500	\$ 2,052	\$ 3,915

Stock Options and SARs. For stock options and Stock SARs that the Company expects to settle in common stock, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally three years). For Cash SARs and any Stock SARs that the Company expects to settle in cash, stock-based compensation expense is based on the fair value remeasured at each reporting period, recognized over the vesting period (generally three years) and classified as other accrued liabilities for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified as other long-term liabilities. Subsequent to vesting, the liability for any SARs that the Company expects to settle in cash is remeasured in earnings at each reporting period based on fair value until the awards are settled. The Company recognizes stock-based compensation expense over the vesting period for stock options and SARs using the straight-line method, except for awards with performance conditions, in which case the Company uses the graded vesting method. Stock options typically expire ten years after the date of grant. SARs typically expire between four and seven years after the date of grant. The Company uses the Black-Scholes-Merton option pricing model to compute the fair value of stock options and SARs.

Restricted Stock Awards and Units. For restricted stock awards and units, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally one to three years) using the straight-line method, except for units with performance conditions, in which case the Company uses the graded vesting method. The fair value of restricted stock awards and units is based on the average of the high and low price of the Company's common stock on the grant date. For restricted stock awards and units granted to independent contractors, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period (generally three years) using the straight-line method.

Foreign Currency

The U.S. dollar is the functional currency for the Company's operations in the U.K. North Sea. Transaction gains or losses that occur due to the realization of assets and the settlement of liabilities using a currency denominated in other than the functional currency are recorded as other income (expense), net in the consolidated statements of operations.

Income Taxes

Deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. The Company routinely assesses the realizability of its deferred tax assets and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments by taxing jurisdiction. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense.

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Net Income Per Common Share

Supplemental net income per common share information is provided below:

	Three Months Ended		Six Months Ended	
	June 30, 2012	2011	June 30, 2012	2011
	(In thousands, except per share amounts)			
Net income	\$28,504	\$7,742	\$37,927	\$8,477
Basic weighted average common shares outstanding	39,596	38,898	39,520	38,841
Effect of dilutive instruments	446	599	467	609
Diluted weighted average common shares outstanding	40,042	39,497	39,987	39,450
Net income per common share				
Basic	\$0.72	\$0.20	\$0.96	\$0.22
Diluted	\$0.71	\$0.20	\$0.95	\$0.21

Basic net income per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the period which include restricted stock awards and units, stock options, warrants and convertible debt. Shares of common stock subject to issuance upon the conversion of the Convertible Senior Notes did not have an effect on the calculation of dilutive shares for the three and six months ended June 30, 2012 or 2011, because the conversion price was in excess of the market price of the common stock for those periods.

3. PROPERTY AND EQUIPMENT, NET

At June 30, 2012 and December 31, 2011, property and equipment, net consisted of the following:

	June 30, 2012	December 31, 2011
	(In thousands)	
Proved oil and gas properties	\$1,433,319	\$1,239,778
Accumulated depreciation, depletion and amortization	(471,714)	(397,737)
Proved oil and gas properties, net	961,605	842,041
Unproved properties and significant development projects, not being amortized		
Unevaluated leasehold and seismic costs	292,310	277,425
Significant development projects	90,280	65,306
Exploratory wells in progress	59,063	70,533
Capitalized interest	49,445	46,471
Total costs not subject to amortization	491,098	459,735
Other property and equipment	16,269	12,835
Accumulated depreciation	(4,825)	(4,097)
Other property and equipment, net	11,444	8,738
Total property and equipment, net	\$1,464,147	\$1,310,514
Sale of Barnett Shale Properties		

During the second quarter of 2012, the Company sold a significant portion of its Barnett Shale properties to an affiliate of Atlas Resource Partners, L.P. ("Atlas") for an agreed upon price of \$190.0 million. Net proceeds received from the sale were approximately \$187.0 million, subject to final post-closing adjustments. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2012 and the closing date of April 30, 2012. The proceeds from such sale were recognized as a reduction of proved oil and gas properties.

4. INCOME TAXES

The Company's estimated annual effective income tax rates are used to allocate expected annual income tax expense to interim

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periods. The rates are the ratio of estimated annual income tax expense to estimated annual income before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the specific transaction occurs. The estimated annual effective income tax rates are applied to the year-to-date income before income taxes by taxing jurisdiction to determine the income tax expense allocated to the interim period. The Company updates its estimated annual effective income tax rate at the end of each quarterly period considering the geographic mix of income based on the tax jurisdictions in which the Company operates. Actual results that are different from the assumptions used in estimating the annual effective income tax rate will impact future income tax expense. Income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate income tax rate of 35% to income before income taxes as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
Income tax expense at the statutory rate	\$15,160	\$3,971	\$19,864	\$4,599
State income taxes, net of U.S. federal income tax benefit	865	127	1,087	1,702
U.K. income tax benefit	(1,320)	(175)	(2,536)	(175)
Capital loss associated with investment in Pinnacle Gas Resources, Inc. for which no income tax benefit was recognized in prior periods	—	—	—	(1,135)
Other, net	105	(321)	413	(329)
Income tax expense	\$14,810	\$3,602	\$18,828	\$4,662

As of June 30, 2012, the Company had U.S. and U.K. income tax loss carryforwards of approximately \$150.9 million and \$105.1 million, respectively. The U.S. loss carryforwards expire between 2019 and 2032 if not utilized in earlier periods. The U.K. loss carryforwards are not subject to expiration as long as the Company maintains an activity trading status in the U.K. The realization of the deferred tax assets related to the loss carryforwards is dependent on the Company's ability to generate sufficient future taxable income, which the Company expects to be able to generate within the applicable carryforward periods. Accordingly, the Company believes that it is more likely than not that its net deferred tax assets will be fully realized.

At June 30, 2012, the Company had no material uncertain tax positions and the tax years since 1999 in the U.S. remain open to review by federal and various state tax jurisdictions. In the U.K., the tax years since 2010 remain open to review by Her Majesty's Revenue and Customs.

5. DEBT

Debt consisted of the following at June 30, 2012 and December 31, 2011:

	June 30, 2012	December 31, 2011
	(In thousands)	
Senior Notes	\$600,000	\$600,000
Unamortized discount for Senior Notes	(5,163)	(5,464)
Convertible Senior Notes	73,750	73,750
Unamortized discount for Convertible Senior Notes	(2,459)	(3,799)
Senior Secured Revolving Credit Facility	130,000	47,000
U.K. Huntington Field Development Project Credit Facility	37,000	17,813
	833,128	729,300
Less: Current maturities of Huntington Facility due June 30, 2013	(16,650)	—
	\$816,478	\$729,300
Senior Notes		

In connection with the issuance of an additional \$200.0 million aggregate principal amount of unregistered Senior Notes ("Senior Notes") that were issued pursuant to a private placement on November 17, 2011, on February 22, 2012, the Company completed the exchange of registered Senior Notes for all of such unregistered Senior Notes.

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Convertible Senior Notes

At June 30, 2012, the Company held \$73.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (the "Convertible Senior Notes"). The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

While the holders of the Convertible Senior Notes may require the Company to repurchase the Convertible Senior Notes in June 2013, the Company has the intent and ability to refinance the Convertible Senior Notes on a long-term basis with the available capacity of its Senior Secured Revolving Credit Facility, and accordingly, the Convertible Senior Notes have been classified as long-term debt in the consolidated balance sheet.

Senior Secured Revolving Credit Facility

The Company is party to a senior secured revolving credit facility ("Revolving Credit Facility") with Wells Fargo Bank, National Association as the administrative agent. The Revolving Credit Facility provides for a borrowing capacity up to the lesser of (i) the borrowing base (as defined in the senior credit agreement governing the Revolving Credit Facility) and (ii) \$750.0 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of the Company's U.S. assets and is guaranteed by certain of the Company's U.S. subsidiaries. The initial borrowing base under the Revolving Credit Facility was \$350.0 million. As a result of the Spring 2012 borrowing base redetermination, effective April 30, 2012, the borrowing base was reduced to \$325.0 million after giving effect to the removal of properties in connection with the recent sale of Barnett Shale properties to Atlas, largely offset by the addition of proved reserves as a result of the Company's successful ongoing drilling program. On March 26, 2012, the Revolving Credit Facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the Revolving Credit Facility) steps down and (2) increase the basket available for redemptions of the Company's Convertible Senior Notes.

The Company is subject to certain covenants under the terms of the Revolving Credit Facility which include the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for the fiscal quarter ending June 30, 2012, (b) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (2) a Current Ratio of not less than 1.00 to 1.00; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the Revolving Credit Facility). At June 30, 2012, the ratio of Total Debt to EBITDA was 3.40 to 1.00, the Current Ratio was 1.13 to 1.00, the ratio of Senior Debt to EBITDA was 0.48 to 1.00 and the ratio of EBITDA to Interest Expense was 4.63 to 1.00. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts outstanding under the Revolving Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

At June 30, 2012, the Company had \$130.0 million of borrowings outstanding under the Revolving Credit Facility with a weighted average interest rate of 2.78%. At June 30, 2012, the Company also had \$1.0 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the \$325.0 million borrowing base is subject to the terms and covenants of the Revolving Credit Facility. The Revolving Credit Facility is used to fund ongoing working capital needs and the remainder of the Company's capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

U.K. Huntington Field Development Project Credit Facility

The Company and Carrizo U.K. Huntington Ltd. ("Carrizo UK"), as borrower, are parties to a Senior Secured Multicurrency Credit Facility (the "Huntington Facility"). The Huntington Facility provides for a multicurrency credit facility consisting of (1) a \$55.0 million term loan facility to be used to fund Carrizo UK's share of project development costs, (2) a \$6.5 million contingent cost overrun term loan facility and (3) a \$22.5 million

post-completion credit facility providing for letters of credit to be used to secure certain abandonment and decommissioning obligations following project completion. The availability under the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014. As of April 1, 2012, following the semi-annual redetermination, the term loan facility and

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cost overrun facility were \$55.0 million and \$6.5 million, respectively.

As of June 30, 2012, borrowings outstanding under the Huntington Facility were \$37.0 million, of which \$16.7 million was classified as current, with a weighted average interest rate of 3.97% and no letters of credit had been issued.

6. COMMITMENTS AND CONTINGENCIES

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a material adverse effect on the financial position or results of operations of the Company.

The operations and financial position and results of operations of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

7. SHAREHOLDERS' EQUITY

On November 24, 2009, the Company entered into a Land Agreement, as amended (the "Land Agreement"), with an unrelated third party and its affiliate. The Land Agreement expired pursuant to its terms on May 31, 2011. Under the Land Agreement, the Company was able to acquire up to \$20.0 million of oil, gas and mineral interests/leases in certain specified areas in the Barnett Shale from such third party. In consideration for the Company's receipt of an option to purchase the leases acquired by the third party, each time the third party purchased a lease group under the Land Agreement the Company agreed to issue to the third party's affiliate warrants to purchase a number of shares of the Company's common stock with an exercise price of \$22.09 and an expiration date of August 21, 2017. In addition, the Company agreed that under certain circumstances where the Company reached surface casing point on an initial well in one of the areas covered by the Land Agreement but has not achieved a specified lease up threshold for acreage in such area, the Company will issue additional warrants. The warrants are subject to antidilution adjustments and may be exercised on a "cashless" basis.

In April 2012, the Company issued warrants to purchase 25,000 shares of the Company's common stock to the third party's affiliate for leases acquired prior to the expiration of the Land Agreement. The April 2012 issuance was the final issuance of warrants under the Land Agreement.

8. DERIVATIVE INSTRUMENTS

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in its forward cash flows supporting its capital expenditure program. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. The Company's current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at June 30, 2012, and December 31, 2011 was a net asset of \$58.6 million and \$37.3 million, respectively. The following sets forth a summary of the distribution of net fair value of the Company's derivative instruments:

Counterparty	June 30, 2012	December 31, 2011	
Credit Suisse	52	% 68	%
BNP Paribas	27	% 19	%
Societe Generale	11	% 2	%
BBVA Compass	6	% —	%

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Shell Energy North America (US) LP	2	% 6	%
Credit Agricole	2	% 5	%
Total	100	% 100	%

Master netting agreements are in place with each of these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, the Company believes it has minimal credit risk

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and accordingly does not currently require its counterparties to post collateral to support the asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the financial viability of its counterparties. Because Credit Suisse, Credit Agricole, BBVA Compass, and Societe Generale are lenders in the Company's Revolving Credit Facility, and BNP Paribas and Societe Generale are lenders in the Company's Huntington Facility, the Company is not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties as the contracts are secured by the Revolving Credit Facility or the Huntington Facility, respectively.

The following sets forth a summary of the Company's U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of June 30, 2012:

Period	Volumes (in MMBtu)	Weighted Average Floor Price (\$/MMBtu)	Weighted Average Ceiling Price (\$/MMBtu)
2012	11,132,000	\$4.96	\$5.13
2013	10,950,000	\$5.07	\$5.07
2014	3,650,000	\$—	\$5.50

In connection with the natural gas derivative instruments above, the Company has entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of \$4.41, the floor price becomes the market price plus the put spread of \$1.02 on 4,296,400 of the 11,132,000 MMBtus and the remaining 6,835,600 MMBtus would have a floor price of \$4.96.

The following sets forth a summary of the Company's U.S. crude oil derivative positions at average NYMEX prices as of June 30, 2012:

Period	Volumes (in Bbls)	Weighted Average Floor Price (\$/Bbl)	Weighted Average Ceiling Price (\$/Bbl)
2012	883,200	\$86.15	\$105.91
2013	1,861,500	\$87.57	\$104.82
2014	1,095,000	\$91.75	\$103.88
2015	620,500	\$92.79	\$97.18

For the three and six months ended June 30, 2012 and 2011, the Company recorded the following related to its oil and gas derivative instruments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(In thousands)			
Realized gain (loss) on derivative instruments, net	\$9,887	\$4,904	\$21,020	\$14,910
Unrealized gain (loss) on derivative instruments, net	28,360	7,161	20,265	(3,032)
Gain (loss) on derivative instruments, net	\$38,247	\$12,065	\$41,285	\$11,878

9. FAIR VALUE MEASUREMENTS

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

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Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis as of June 30, 2012 and December 31, 2011, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(In thousands)								
Assets:								
Derivative instruments	\$—	\$72,683	\$—	\$72,683	\$—	\$61,073	\$—	\$61,073
Liabilities:								
Derivative instruments	—	(14,088)	—	(14,088)	—	(23,792)	—	(23,792)
Total	\$—	\$58,595	\$—	\$58,595	\$—	\$37,281	\$—	\$37,281

The fair values of the Company's derivative instruments are based on a pricing model that uses market data obtained from reputable independent sources and are considered Level 2 inputs, including (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The estimates of fair value are also compared to the values provided by the counterparty for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

The fair values reported in the consolidated balance sheets are as of a particular point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. The assets and liabilities for derivative instruments included in the tables above are presented on a gross basis. The assets and liabilities for derivative instruments included in the consolidated balance sheets are presented on a net basis when such amounts are with the same counterparty and subject to master netting agreements. The Company had no transfers in or out of Levels 1 or 2 for the six months ended June 30, 2012 or 2011.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, receivables, payables and debt which are all classified as Level 1 under the fair value hierarchy. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amounts of debt under the Revolving Credit Facility and the Huntington Facility approximate fair value as these borrowings bear interest at variable rates of interest. The fair value of the Convertible Senior Notes at June 30, 2012 and December 31, 2011 was estimated at approximately \$73.3 million and \$73.0 million, respectively, based on quoted market prices. The fair value of the Senior Notes at June 30, 2012 and December 31, 2011 was estimated at approximately \$627.0 million and \$606.0 million, respectively, based on quoted market prices. See Note 5. Debt for the carrying amounts of the Convertible Senior Notes and Senior Notes.

10. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In November 2010 and November 2011, the Company and certain of the Company's wholly owned subsidiaries (such subsidiaries collectively, the "Subsidiary Guarantors") issued in private placements \$400.0 million and \$200.0 million, respectively, aggregate principal amount of the Company's Senior Notes. Certain, but not all, of the Company's wholly owned subsidiaries have issued full, unconditional and joint and several guarantees of the Senior Notes and may guarantee future issuances of debt securities. In June 2011 and February 2012, the Company completed the exchange of registered 8.625% Senior Notes due 2018 for any and all of its unregistered \$400.0 million and \$200.0 million aggregate principal amount of 8.625% Senior Notes due 2018, respectively.

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information as of June 30, 2012 and December 31, 2011, and for the three and six months ended June 30, 2012 and 2011 on a parent company, combined guarantor subsidiaries, combined

non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the Subsidiary Guarantors operated as independent entities.

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Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company's oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

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CONDENSED CONSOLIDATING BALANCE SHEETS

June 30, 2012

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	\$1,440,016	\$111,247	\$1,487	\$(1,404,603)) \$148,147
Property and equipment, net	108,699	1,234,104	98,317	23,027	1,464,147
Investments in subsidiaries	(21,347)) —	—	21,347	—
Other assets	51,012	38,499	11,237	(8,400)) 92,348
Total assets	\$1,578,380	\$1,383,850	\$111,041	\$(1,368,629)) \$1,704,642
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	\$171,965	\$1,466,599	\$21,553	\$(1,345,415)) \$314,702
Long-term liabilities	804,554	2,232	25,854	—	832,640
Shareholders' equity	601,861	(84,981)) 63,634	(23,214)) 557,300
Total liabilities and shareholders' equity	\$1,578,380	\$1,383,850	\$111,041	\$(1,368,629)) \$1,704,642

December 31, 2011

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets	\$1,349,841	\$71,018	\$3,874	\$(1,304,336)) \$120,397
Property and equipment, net	101,015	1,131,672	68,911	8,916	1,310,514
Investments in subsidiaries	(58,764)) —	—	58,764	—
Other assets	38,853	54,062	9,133	(5,279)) 96,769
Total assets	\$1,430,945	\$1,256,752	\$81,918	\$(1,241,935)) \$1,527,680
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities	\$150,793	\$1,368,456	\$4,366	\$(1,252,295)) \$271,320
Long-term liabilities	724,801	2,183	22,429	(2,908)) 746,505
Shareholders' equity	555,351	(113,887)) 55,123	13,268	509,855
Total liabilities and shareholders' equity	\$1,430,945	\$1,256,752	\$81,918	\$(1,241,935)) \$1,527,680

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For The Three Months Ended June 30, 2012

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated	
	(In thousands)					
Oil and gas revenues	\$4,608	\$79,210	\$—	\$—	\$83,818	
Cost and expenses	32,818	51,429	75	(15,223) 69,099	
Operating income (loss)	(28,210) 27,781	(75) 15,223	14,719	
Other income and (expense), net	34,187	(7,014) 1,422	—	28,595	
Income (loss) before income taxes	5,977	20,767	1,347	15,223	43,314	
Income tax (expense) benefit	(2,092) (7,268) 1,320	(6,770) (14,810)
Equity in income (loss) of subsidiaries	16,166	—	—	(16,166) —	
Net income (loss)	\$20,051	\$13,499	\$2,667	\$(7,713) \$28,504	

For The Three Months Ended June 30, 2011

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated	
	(In thousands)					
Oil and gas revenues	\$9,389	\$41,283	\$—	\$—	\$50,672	
Cost and expenses	21,788	24,237	143	(1,534) 44,634	
Operating income (loss)	(12,399) 17,046	(143) 1,534	6,038	
Other income and (expense), net	15,242	(8,255) (1,681) —	5,306	
Income before income taxes	2,843	8,791	(1,824) 1,534	11,344	
Income tax (expense) benefit	(784) (3,230) 976	(564) (3,602)
Equity in income (loss) of subsidiaries	4,713	—	—	(4,713) —	
Net income (loss)	\$6,772	\$5,561	\$(848) \$(3,743) \$7,742	

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

For The Six Months Ended June 30, 2012

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	\$11,397	\$153,136	\$—	\$—	\$164,533
Cost and expenses	47,365	94,107	153	(14,112)) 127,513
Operating income (loss)	(35,968)) 59,029	(153)) 14,112	37,020
Other income and (expense), net	35,314	(14,560)) (1,019)) —	19,735
Income (loss) before income taxes	(654)) 44,469	(1,172)) 14,112	56,755
Income tax (expense) benefit	229	(15,564)) 2,536	(6,029)) (18,828)
Equity in income (loss) of subsidiaries	30,269	—	—	(30,269)) —
Net income (loss)	\$29,844	\$28,905	\$1,364	\$(22,186)) \$37,927

For The Six Months Ended June 30, 2011

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Oil and gas revenues	\$18,164	\$76,566	\$—	\$—	\$94,730
Cost and expenses	37,969	43,647	143	(2,832)) 78,927
Operating income (loss)	(19,805)) 32,919	(143)) 2,832	15,803
Other income and (expense), net	11,098	(12,081)) (1,681)) —	(2,664)
Income before income taxes	(8,707)) 20,838	(1,824)) 2,832	13,139
Income tax (expense) benefit	3,059	(7,656)) 976	(1,041)) (4,662)
Equity in income (loss) of subsidiaries	12,334	—	—	(12,334)) —
Net income (loss)	\$6,686	\$13,182	\$(848)	\$(10,543)) \$8,477

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CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For The Six Months Ended June 30, 2012

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by operating activities	\$44,412	\$101,585	\$(898)) \$—	\$145,099
Net cash used in investing activities	(158,119)) (188,743)) (26,805)) 119,927	(253,740)
Net cash provided by financing activities	101,298	93,120	26,807	(119,927)) 101,298
Net increase (decrease) in cash and cash equivalents	(12,409)) 5,962	(896)) —	(7,343)
Cash and cash equivalents, beginning of period	19,134	7,263	1,715	—	28,112
Cash and cash equivalents, end of period	\$6,725	\$13,225	\$819	\$—	\$20,769

For The Six Months Ended June 30, 2011

	Parent Company	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Net cash provided by operating activities	\$18,563	\$56,042	\$(483)) \$—	\$74,122
Net cash used in investing activities	(57,759)) (114,348)) (35,130)) 114,121	(93,116)
Net cash provided by financing activities	42,199	65,766	45,124	(114,121)) 38,968
Net increase (decrease) in cash and cash equivalents	3,003	7,460	9,511	—	19,974
Cash and cash equivalents, beginning of period	1,418	2,710	—	—	4,128
Cash and cash equivalents, end of period	\$4,421	\$10,170	\$9,511	\$—	\$24,102

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

The following is management's discussion and analysis of the significant factors that affected the Company's financial position and results of operations during the periods included in the accompanying unaudited consolidated financial statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2011, and the unaudited consolidated financial statements included in this quarterly report.

General Overview

Our second quarter 2012 included oil and gas revenues of \$83.8 million and production of 2,393 Mboe. The key drivers to our results for the three months ended June 30, 2012 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the three months ended June 30, 2012, we drilled (a) 15 gross wells (11.7 net) in the Eagle Ford Shale, (b) 13 gross wells (2.9 net) in the Marcellus Shale, (c) 8 gross wells (5.1 net) in the Niobrara Formation, and (d) 1 gross well (0.2 net) in the U.K. North Sea.

Production. Our second quarter 2012 production of 2,393 Mboe (14.4 Bcfe) increased 29% from the second quarter 2011 production of 1,862 Mboe (11.2 Bcfe). The increase in production from the second quarter of 2011 to the second quarter of 2012 was primarily due to increased production from new wells primarily in the Eagle Ford Shale and the Niobrara Formation, partially offset by normal production decline, and the sale of substantially all of our non-core area Barnett Shale properties to KKR Natural Resources ("KKR") in May 2011 and the sale of a significant portion of our remaining Barnett Shale properties to Atlas Resource Partners, L.P. ("Atlas") in April 2012.

Commodity prices. Our average realized oil price during the second quarter of 2012 was \$98.92 per barrel, or 1% higher than the price during the second quarter of 2011. Our average realized gas price during the second quarter of 2012 was \$1.32 per Mcf, or 59% lower than the price during the second quarter of 2011.

Sale of Barnett Shale Properties. In April 2012, we completed the sale of a significant portion of our remaining Barnett Shale properties to Atlas for an agreed upon price of \$190.0 million. Net proceeds received from the sale were approximately \$187.0 million in cash, subject to final post-closing adjustments. The purchase price adjustments primarily related to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2012 and the closing date of April 30, 2012. The net proceeds have been recognized as a reduction of the Company's capitalized oil and gas property costs and accordingly, no gain or loss was recognized as a result of the sale. The sale included approximately 221 gross (110 net) wells that produced at an approximate net rate of 35 MMcfe per day. Estimated total proved reserves associated with the divested properties, as determined by Carrizo's third party engineer at year-end 2011, were approximately 312 Bcfe (comprised of 177 Bcfe of proved developed and 135 Bcfe of proved undeveloped reserves), of which 53 Bcfe were non-operated. The Company used substantially all of the net proceeds from this sale to reduce the outstanding borrowings under its Revolving Credit Facility.

Outlook

While the market for natural gas remains challenging due to low spot and future prices, we are insulated from a portion of their effect by our hedging of 11,132,000 MMBtus of natural gas at June 30, 2012 for the remainder of 2012. The Atlas and KKR sales and our rapidly growing oil production, further serve to reduce our exposure to the natural gas market. The current market and outlook for crude oil is much more attractive and we are aggressively locking in these prices by increasing our hedge positions as our oil production grows. At June 30, 2012, we had hedges in place for 883,200 bbls of oil for the remainder of 2012. Production growth and commodity prices that permit us to drill, develop and produce at a profit are key to our future success.

Eagle Ford and Niobrara. Based upon the success of our drilling results since late 2010, we continue to focus on developing our liquid rich resource plays in the Eagle Ford Shale and the Niobrara Formation and have reallocated capital from development of Barnett Shale and Marcellus Shale gas to Eagle Ford and Niobrara oil. As of June 30, 2012, we had 45 wells producing in the Eagle Ford Shale and 19 wells producing in the Niobrara Formation. As of

July 31, 2012, we were operating three rigs on our Eagle Ford properties and one rig on our Niobrara properties. Marcellus Shale. As a result of the material decline in natural gas prices, we and our joint venture partners are carefully reviewing our drilling program and have significantly reduced our planned spending in the Marcellus Shale during 2012. We will continue to monitor prices and, consistent with our existing contractual commitments, may decrease our activity level and capital expenditures further, or may increase such activity, if natural gas prices so warrant. As of June 30, 2012, we had 21 wells producing in the Marcellus Shale. As of July 31, 2012 we were operating one rig on our Marcellus properties.

Barnett Shale. During the second quarter we completed the drilling of one well and, as of July 31, 2012, were operating no rigs on our Barnett properties.

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U.K. North Sea. During the second quarter of 2012, we continued development of the Huntington Field. As of July 31, 2012, all producer and injector wells had been completed. We currently expect production from this field to begin in the fourth quarter of 2012.

Results of Operations

Three Months Ended June 30, 2012, Compared to the Three Months Ended June 30, 2011

Revenues from oil and gas production for the three months ended June 30, 2012 increased 65% to \$83.8 million from \$50.7 million for the same period in 2011 primarily due to increased oil production and higher oil prices partially offset by lower gas prices. Production volumes for the three months ended June 30, 2012 and 2011 were 2,393 Mboe and 1,862 Mboe, respectively. The increase in production from the second quarter of 2011 to the second quarter of 2012 was primarily due to increased production from new wells, partially offset by normal production decline, the sale of substantially all of our non-core area Barnett Shale properties to KKR in May 2011 and the sale of a significant portion of our remaining properties in the Barnett Shale to a subsidiary of Atlas in April 2012. Average realized gas prices decreased 59% to \$1.32 per Mcf in the second quarter of 2012 from \$3.25 per Mcf in the same period in 2011. Average realized oil prices increased 1% to \$98.92 per barrel from \$98.02 per barrel in the same period in 2011. The following table summarizes production volumes, average realized sales prices and oil and gas revenues for the three months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		2012 Period Compared to 2011 Period		
	2012	2011	Increase (Decrease)	% Increase (Decrease)	
Production volumes					
Oil and condensate (MBbls)	693	158	535	338	%
Natural gas (MMcf)	9,808	9,803	5	—	%
NGLs (Mboe)	65	70	(5)	(7))%
Total oil and gas production (Mboe)	2,393	1,862	531	29	%
Average realized sales prices					
Oil and condensate (per Bbl)	\$98.92	\$98.02	\$0.90	1	%
Natural gas (per Mcf)	1.32	3.25	(1.93)	(59))%
NGLs (per Boe)	34.97	47.16	(12.19)	(26))%
Total average realized sales price (per Boe)	\$35.03	\$27.21	\$7.82	29	%
Oil and gas revenues (In thousands)					
Oil and condensate	\$68,576	\$15,530	\$53,046	342	%
Natural gas	12,964	31,840	(18,876)	(59))%
NGLs	2,278	3,302	(1,024)	(31))%
Total oil and gas revenues	\$83,818	\$50,672	\$33,146	65	%

Lease operating expenses were \$7.0 million (or \$2.94 per Boe or \$0.49 per Mcfe) for the three months ended June 30, 2012 as compared to lease operating expenses of \$7.4 million (or \$3.99 per Boe or \$0.66 per Mcfe) for the second quarter of 2011. The \$0.4 million decrease in lease operating expenses is primarily due to the Atlas and KKR sales partially offset by increased production. The decrease in operating cost per unit is primarily due to the Atlas and KKR sales (which were higher operating cost per unit properties compared to our remaining Barnett Shale properties) partially offset by the higher operating cost per unit associated with oil production.

Production taxes were \$3.1 million (or 3.7% of oil and gas revenues) for the three months ended June 30, 2012 as compared to \$1.5 million (or 2.9% of oil and gas revenues) for the three months ended June 30, 2011. The increase in production taxes is due primarily to increased oil production. The increase in production taxes as a percentage of oil and gas revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

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Ad valorem taxes increased to \$2.3 million (or \$0.96 per Boe or \$0.16 per Mcfe) for the three months ended June 30, 2012 from \$1.0 million (\$0.53 per Boe or \$0.09 per Mcfe) for the same period in 2011. The increase in ad valorem taxes is due primarily to new oil wells drilled in 2011. The increase in ad valorem taxes per unit is due primarily to new oil wells drilled in 2011, which have higher property tax valuations as compared to our natural gas wells.

Depreciation, depletion and amortization (“DD&A”) expense for the second quarter of 2012 increased \$22.8 million to \$43.4 million (\$18.12 per Boe or \$3.02 per Mcfe) from the DD&A expense for the second quarter of 2011 of \$20.6 million (\$11.04 per Boe or \$1.84 per Mcfe). The \$22.8 million increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per unit. The increase in the DD&A rate per unit is largely due to the impact of the significant decrease in natural gas reserves in the Barnett Shale as result of the Atlas sale as well as the significant increase in crude oil reserves in the Eagle Ford that were added in 2011, which have a higher finding cost per equivalent unit than our natural gas reserves.

General and administrative expense decreased to \$13.1 million for the three months ended June 30, 2012 from \$14.1 million for the corresponding period in 2011. The decrease was primarily due to decreased stock-based compensation expense which was primarily driven by a decrease in the fair value of cash-settled stock appreciation rights due to a decrease in stock price during the second quarter of 2012 as compared to an increase in stock price during the second quarter of 2011, partially offset by an increase in the number of restricted stock awards outstanding during second quarter of 2012 as compared to the second quarter of 2011 and increased compensation costs related to an increase in personnel in the second quarter of 2012 as compared to the second quarter of 2011.

The net gain on derivative instruments of \$38.3 million in the second quarter of 2012 consisted of an \$28.4 million unrealized gain on derivatives and a \$9.9 million realized gain on derivatives. The net gain on derivative instruments of \$12.1 million in the second quarter of 2011 was comprised of a \$7.2 million unrealized gain on derivatives and a \$4.9 million realized gain on derivatives.

Interest expense and capitalized interest for the three months ended June 30, 2012 were \$17.7 million and \$7.8 million, respectively, as compared to \$12.4 million and \$5.6 million, respectively, for the same period in 2011. The increase in interest expense was primarily due to interest on the \$200 million aggregate principal amount of our Senior Notes that were issued in the fourth quarter of 2011. The increase in capitalized interest was primarily related the U.K. Huntington field development project.

The estimated annual effective income tax rates for 2012 and 2011 were 37.1% and 36.7%, respectively. The effective income tax rates for the second quarter of 2012 and 2011 were 34.2% and 31.8%, respectively, which were lower than the estimated annual effective income tax rates due to the foreign tax benefit of our U.K. Huntington field development project.

Six Months Ended June 30, 2012, Compared to the Six Months Ended June 30, 2011

Revenues from oil and gas production for the six months ended June 30, 2012 increased 74% to \$164.5 million from \$94.7 million for the same period in 2011 primarily due to increased production and higher oil prices, partially offset by lower gas prices. Production volumes for the six months ended June 30, 2012 and 2011 were 4,704 Mboe and 3,644 Mboe, respectively. The increase in production for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011 was primarily due to increased production from new wells, partially offset by normal production decline and the Atlas and KKR sales. Average realized gas prices decreased 49% to \$1.60 per Mcf for the first six months of 2012 from \$3.16 per Mcf in the same period in 2011. Average realized oil prices increased 11% to \$103.66 per barrel from \$93.74 per barrel in the same period in 2011.

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The following table summarizes production volumes, average realized sales prices and oil and gas revenues for the six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,		2012 Period Compared to 2011 Period		
	2012	2011	Increase (Decrease)	% Increase (Decrease)	
Production volumes					
Oil and condensate (MBbls)	1,234	292	942	323	%
Natural gas (MMcf)	20,135	19,282	853	4	%
NGLs (Mboe)	114	139	(25)	(18))%
Total oil and gas production (Mboe)	4,704	3,644	1,060	29	%
Average realized sales prices					
Oil and condensate (per Bbl)	\$ 103.66	\$ 93.74	\$ 9.92	11	%
Natural gas (per Mcf)	1.60	3.16	(1.56)	(49))%
NGLs (per Boe)	39.00	47.00	(8.00)	(17))%
Total average realized sales prices (per Boe)	\$ 34.98	\$ 26.00	\$ 8.98	35	%
Oil and gas revenues (In thousands)					
Oil and condensate	\$ 127,945	\$ 27,360	\$ 100,585	368	%
Natural gas	32,151	60,851	(28,700)	(47))%
NGLs	4,437	6,519	(2,082)	(32))%
Total oil and gas revenues	\$ 164,533	\$ 94,730	\$ 69,803	74	%

Lease operating expenses were \$15.5 million (or \$3.29 per Boe or \$0.55 per Mcfe) for the six months ended June 30, 2012 as compared to lease operating expenses of \$14.1 million (or \$3.87 per Boe or \$0.64 per Mcfe) for the six months ended June 30, 2011. Lease operating expenses increased \$2.1 million primarily due to increased production from new wells partially offset by the Atlas and KKR sales. The decrease in operating cost per unit is due to the Atlas and KKR sales (which were higher operating cost per unit properties as compared to our remaining Barnett Shale properties) partially offset by the higher operating cost per unit associated with oil production.

Production taxes increased to \$6.2 million (or 3.8% of oil and gas revenues) for the six months ended June 30, 2012 from \$2.4 million (or 2.5% of oil and gas revenues) for the six months ended June 30, 2011. The increase in production taxes is due primarily to increased oil production. The increase in production taxes as a percentage of oil and gas revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

Ad valorem taxes increased to \$5.9 million (\$1.26 per Boe or \$0.21 per Mcfe) for the six months ended June 30, 2012 from \$1.7 million (\$0.46 per Boe or \$0.08 per Mcfe) for the same period in 2011. The increase in ad valorem taxes is due primarily to new oil wells drilled in 2011 and the commonwealth of Pennsylvania's February 2012 enactment of an "impact fee" on the drilling of unconventional natural gas wells. Because of the retroactive nature of the impact fee, approximately \$1.2 million of ad valorem taxes recognized during the first six months of 2012 is attributable to wells drilled prior to 2012. The increase in ad valorem taxes per unit is due primarily to new oil wells drilled in 2011, which have higher property tax valuations as compared to our natural gas wells, as well as the recognition of the impact fee in 2012.

DD&A expense for the six months ended June 30, 2012 increased \$37.7 million to \$74.9 million (or \$15.96 per Boe or \$2.66 per Mcfe) from \$37.3 million (or \$10.20 per Boe or \$1.70 per Mcfe) for the same period in 2011. The \$37.7 million increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per unit. The increase in the DD&A rate per unit is largely due to the impact of the significant decrease in natural gas reserves

in the Barnett Shale as a result of the Atlas and KKR sales as well as the increase in crude oil reserves in the Eagle Ford that were added in 2011, which have a higher finding cost per equivalent unit than our natural gas reserves.

General and administrative expense increased to \$24.6 million for the six months ended June 30, 2012 from \$23.3 million for the corresponding period in 2011. The increase was primarily due to increased compensation costs related to an increase in personnel in the six months ended June 30, 2012 as compared to the six months ended June 30, 2011, higher stock-based compensation expense due to a higher number of restricted stock awards outstanding during the six months ended June 30, 2012 as compared to the same period of 2011, partially offset by a decrease in the fair value of cash-settled stock appreciation rights due to a decrease

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in stock price during the six months ended June 30, 2012 as compared to an increase in stock price during the same period of 2011.

The net gain on derivative instruments of \$41.3 million in the first six months of 2012 consisted of a \$20.3 million unrealized gain on derivatives and a \$21.0 million realized gain on derivatives. The net gain on derivative instruments of \$11.9 million in the first six months of 2011 was comprised of a \$14.9 million realized gain on derivatives and a \$3.0 million unrealized loss on derivatives.

Interest expense and capitalized interest for the six months ended June 30, 2012 were \$35.0 million and \$13.8 million, respectively, as compared to \$24.6 million and \$10.9 million, respectively, for the same period in 2011. The increase in interest expense was primarily due to interest on the \$200 million aggregate principal amount of our Senior Notes that were issued in the fourth quarter of 2011. The increase in capitalized interest was primarily related the U.K. Huntington field development project.

The estimated annual effective income tax rates for 2012 and 2011 were 37.1% and 36.7%, respectively. The effective income tax rates for the six months ended June 30, 2012 and 2011 were 33.2% and 35.5%, respectively, which were lower than the estimated annual effective income tax rates due to the foreign tax benefit of our U.K. Huntington field development project.

Liquidity and Capital Resources

2012 Capital Expenditure Plan and Funding Strategy. In August 2012, our Board approved a revised U.S. capital expenditure plan of \$600.0 million which includes approximately \$378.0 million for the Eagle Ford Shale, \$61.0 million for the Niobrara Formation, \$54.0 million for the Marcellus Shale, \$29.0 million for the Barnett Shale, and \$78.0 million for other areas, inclusive of carries. Planned capital expenditures for the Huntington Field development project in the U.K. North Sea are \$35.0 million, all of which is expected to be funded by our Huntington Facility. We intend to finance the remainder of our 2012 capital expenditure plan primarily from the sources described below under “ – Sources and Uses of Cash.” Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic data acquisition programs. The actual amount of investment could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. For the six months ended June 30, 2012, we funded our capital expenditures with cash provided by operations, payments or carried interest relating to our joint ventures with Reliance and GAIL, net proceeds from the Atlas sale and borrowings under our Revolving Credit Facility and the Huntington Facility. Potential sources of future liquidity include the following:

Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oilfield services. We hedge a portion of our production to mitigate the risk of a decline in oil and gas prices.

Borrowings under the Revolving Credit Facility and the Huntington Facility. At July 31, 2012, \$190.0 million and \$40.0 million of borrowings were outstanding under the Revolving Credit Facility and the Huntington Facility, respectively. At July 31, 2012, we also had \$1.0 million in letters of credit outstanding under the Revolving Credit Facility, which reduce the amounts available under the Revolving Credit Facility. The amount we are able to borrow with respect to the borrowing base of the Revolving Credit Facility, which borrowing base is currently \$325.0 million, is subject to compliance with the financial covenants and other provisions of the credit agreement governing the Revolving Credit Facility.

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Borrowings under project financing arrangements in certain limited circumstances. As described above, we plan to fund a substantial portion of our remaining costs relating to development of the Huntington Field from our Huntington Facility.

Asset sales. On April 30, 2012, we completed the sale of a significant portion of our Barnett Shale properties to Atlas for an agreed upon price of \$190.0 million. Net proceeds received from the sale were approximately \$187.0 million, subject to final post-closing adjustments. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2012 and the closing date of April 30, 2012. We used substantially all of the net proceeds from this sale to reduce the outstanding borrowings under the Revolving Credit Facility. In order to further fund our capital expenditure plan, we may consider additional sales of certain properties or assets, including our interest in the Huntington field development project in the U.K. North Sea, as well as other properties such as certain of our Gulf Coast properties, that are not part of our core business, or are no longer deemed essential to our future growth, and provided that we are able to sell such assets on terms that are acceptable to us.

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Securities offerings. As situations or conditions arise, we may choose to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.

Lease option agreements and land banking arrangements, such as those we have entered into in the Barnett Shale and other plays.

Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage and/or purchase a portion of interests, such as our joint ventures with Reliance in the Marcellus Shale, and with GAIL in the Eagle Ford Shale.

Overview of Cash Flow Activities. Net cash provided by operating activities was \$145.1 million and \$74.1 million for the six months ended June 30, 2012 and 2011, respectively. The increase was primarily due to increased crude oil production and prices, partially offset by lower gas prices in the first six months of 2012 as compared to the same period in 2011.

Net cash used in investing activities was \$253.7 million and \$93.1 million for the six months ended June 30, 2012 and 2011, respectively, and increased primarily due to increased capital expenditures particularly related to our increased Eagle Ford drilling program, partially offset by an increase in proceeds from sales of oil and gas properties.

Net cash provided by financing activities for the six months ended June 30, 2012 and 2011 was \$101.3 million and \$39.0 million, respectively. The increase related primarily to the increased net borrowings under the Revolving Credit Facility and the Huntington Facility during the first six months of 2012 as compared to the first six months of 2011.

Liquidity/Cash Flow Outlook. Economic downturns may adversely affect our ability to access capital markets in the future. We currently believe that cash provided by operating activities, the sale of assets (including our recent sale of Barnett Shale properties to Atlas) and borrowings under the Revolving Credit Facility and the Huntington Facility will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities is primarily driven by production and commodity prices. While we have steadily increased production over the last few years, spot and futures prices of natural gas remain depressed. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows that will support our capital expenditures program, we hedge a portion of our production and, as of July 31, 2012, we had hedged approximately 9,024,000 MMBtu (59,000 MMBtu per day for the remainder of 2012) of our estimated August through December 2012 natural gas production at a weighted average floor or swap price of \$5.02 per MMBtu relative to WAHA and Houston Ship Channel prices. Additionally, we had hedged approximately 734,400 Bbls (4,800 Bbls per day for the remainder of 2012) of our estimated August through December 2012 crude oil production at a weighted average floor or swap price of \$86.15 per Bbl relative to NYMEX prices. As of July 31, 2012, we had borrowings outstanding of \$190.0 million and \$40.0 million under our Revolving Credit Facility and Huntington Facility, respectively. Our borrowing base under our Revolving Credit Facility is currently \$325.0 million. At July 31, 2012, we also had \$1.0 million in letters of credit outstanding, which reduce the amounts available under the Revolving Credit Facility. Additionally, as noted under “—Sources and Uses of Cash” above, the amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the Revolving Credit Facility. The borrowing base is affected by our lenders’ assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base. The next borrowing base redetermination is scheduled to occur in the third quarter of 2012.

If cash provided by operating activities, proceeds from asset sales, funds available under the Revolving Credit Facility and the Huntington Facility and the other sources of cash described under “—Sources and Uses of Cash” are insufficient to fund the remainder of our revised 2012 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives to fund it. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer a portion of our revised 2012 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may use a portion of our internally generated cash flows, proceeds from asset sales or borrowings or cash on hand to reduce debt prior to scheduled maturities through debt repurchases, either in the open

market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings.

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Contractual Obligations

The following table sets forth estimates of our contractual obligations as of June 30, 2012 (in thousands):

	2012	2013	2014	2015	2016	2017 and Beyond	Total
Debt (1)	\$—	\$24,050	\$12,950	\$—	\$203,750	\$600,000	\$840,750
Interest on debt (2)	32,575	59,797	59,146	57,678	52,194	103,500	364,890
Operating leases	51	1,216	1,388	1,370	1,370	7,533	12,928
Drilling contracts	24,206	41,158	30,509	7,904	—	—	103,777
Pipeline volume commitments	5,805	16,149	17,136	15,150	8,711	1,411	64,362
Asset retirement obligations	1,093	189	313	78	61	11,545	13,279
Seismic obligations	1,907	—	—	—	—	—	1,907
Other	1,243	660	104	—	—	—	2,007
Total Contractual Obligations	\$66,880	\$143,219	\$121,546	\$82,180	\$266,086	\$723,989	\$1,403,900

(1) Noteholders may require us to repurchase the Convertible Senior Notes in June 2013, June 2018 or June 2023. The Company has the intent and ability to refinance the Convertible Senior Notes on a long-term basis with the available capacity of its Senior Secured Revolving Credit Facility, which matures in 2016, and accordingly, the Convertible Senior Notes have been presented as a 2016 contractual obligation.

(2) Interest on long-term debt is based on the 8.625% rate on the Senior Notes, the 4.375% rate on the Convertible Senior Notes until June 1, 2013 and the Revolving Credit Facility rate of 2.78% thereafter reflecting our intent and ability to refinance the Convertible Senior Notes with the available capacity under our Revolving Credit Facility, the June 30, 2012 average interest rate of 2.78% for amounts outstanding under our Revolving Credit Facility and the June 30, 2012 average interest rate of 3.97% for amounts outstanding under the Huntington Facility.

Financing Arrangements

Senior Secured Revolving Credit Facility

In January 2011, we entered into the Revolving Credit Facility which provides for a borrowing capacity up to the lesser of (i) the Borrowing Base and (ii) \$750.0 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of our assets (excluding our Carrizo UK assets described below under “—Huntington Field Development Project Credit Facility” and our Utica Shale assets) and is guaranteed by certain of our subsidiaries: Bandelier Pipeline Holding, LLC, Carrizo (Eagle Ford) LLC, Carrizo Marcellus Holding Inc., Carrizo (Marcellus) LLC, Carrizo (Marcellus) WV LLC, Carrizo (Niobrara) LLC, CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, LLC. Any subsidiary of ours that does not currently guarantee our obligations under our Revolving Credit Facility that subsequently becomes a material domestic subsidiary (as defined under our Revolving Credit Facility) will be required to guarantee our obligations under our Revolving Credit Facility. The initial borrowing base under the Revolving Credit Facility was \$350.0 million. As a result of the Spring 2012 borrowing base redetermination, effective April 30, 2012, the borrowing base was reduced to \$325.0 million after giving effect to the removal of properties in connection with the recent sale of Barnett Shale properties to Atlas, largely offset by the addition of proved reserves as a result of the Company's successful ongoing drilling program. The next borrowing base redetermination is expected to occur in the third quarter of 2012.

On March 26, 2012, the Revolving Credit Facility was amended to, among other things, (1) extend by two quarters the dates on which the maximum ratio of Total Debt to EBITDA (each as defined in the credit agreement governing the Revolving Credit Facility) steps down and (2) increase the basket available for redemptions of our Convertible Senior Notes from \$30.0 million to \$75.0 million.

We are subject to certain covenants under the terms of the Revolving Credit Facility which include the maintenance of the following financial covenants: (1) a ratio of Total Debt to EBITDA of not more than (a) 4.75 to 1.00 for the fiscal quarter ending June 30, 2012, (b) 4.25 to 1.00 for fiscal quarters ending September 30, 2012 and December 31, 2012

and (c) 4.00 to 1.00 for fiscal quarters ending March 31, 2013 and thereafter; (2) a Current Ratio of not less than 1.00 to 1.00; (3) a ratio of Senior Debt to EBITDA of not more than 2.50 to 1.00; and (4) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00 (each of the capitalized terms used in the foregoing clauses (1) through (4) being as defined in the credit agreement governing the Revolving Credit Facility). At June 30, 2012, the ratio of Total Debt to EBITDA was 3.40 to 1.00, the Current Ratio was 1.13 to 1.00, the ratio of Senior Debt to EBITDA was 0.48 to 1.00 and the ratio of EBITDA to Interest Expense was 4.63 to 1.00. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts

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outstanding under the Revolving Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

The Revolving Credit Facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Revolving Credit Facility is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing the Revolving Credit Facility) may accelerate amounts due under the Revolving Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

At June 30, 2012, we had \$130.0 million of borrowings outstanding under the Revolving Credit Facility with a weighted average interest rate of 2.78%. At June 30, 2012, we also had \$1.0 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. Future availability under the \$325.0 million borrowing base is subject to the terms and covenants of the Revolving Credit Facility. The Revolving Credit Facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

U.K. Huntington Field Development Project Credit Facility

On January 28, 2011, we and Carrizo UK, as borrower, entered into the Huntington Facility. The Huntington Facility is secured by substantially all of Carrizo UK's assets and is limited recourse to us. The Huntington Facility provides financing for a substantial portion of Carrizo UK's share of costs associated with the Huntington Field development project in the U.K. North Sea. The Huntington Facility provides for a multicurrency credit facility consisting of (1) a \$55.0 million term loan facility to be used to fund Carrizo UK's share of project development costs, (2) a \$6.5 million contingent cost overrun term loan facility and (3) a \$22.5 million post-completion credit facility providing for letters of credit to be used to secure certain abandonment and decommissioning obligations following project completion. Availability under each of the term loan facility and the cost overrun facility is subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK attributable to certain proved reserves in the Huntington Field project. The availability under the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field project. As of April 1, 2012, following the semi-annual redetermination of the borrowing base, the term loan facility and cost overrun facility were \$55.0 million and \$6.5 million, respectively.

Initial borrowings under the term loan facility and cost overrun facility were conditioned on, among other things, our having made an approximate \$22.5 million equity contribution to Carrizo UK, which was completed during the first quarter of 2011. Prior to project completion, we may be responsible under the Huntington Facility for making an additional equity contribution to Carrizo UK in the event the term loan borrowing base is reduced to a level at or above the amount of borrowings then outstanding. We may also be responsible under the Huntington Facility for making certain additional equity contributions to Carrizo UK in the event of certain specified projected Cost Overruns (as defined in the Huntington Facility). To the extent that the cost overrun facility and any required equity contributions are insufficient, we are responsible for funding any Cost Overruns on a 100% basis. If after project completion, the lenders reasonably determine that Carrizo UK is required to incur additional capital expenditures that were not contemplated by the Huntington Field development plan originally approved by the U.K. Department of Energy and Climate Change, we will be responsible for funding such additional expenditures. We are responsible for making certain other payments under the Huntington Facility, including funding certain projected working capital shortfalls, providing cash collateral for letters of credit issued under the post-completion credit facility and paying certain costs of the required hedging arrangements described below.

The annual interest rate on each borrowing is (a) LIBOR (EURIBOR for euro-denominated loans) for the applicable interest period, plus (b) a margin of (i) 3.50% until the completion of the Huntington Field development project and 3.0% thereafter for the term loan credit facility and post-completion credit facility or (ii) 4.75% for the cost overrun

facility.

Borrowings under the term loan and cost overrun facilities are available until the earlier of June 30, 2013 or the achievement of certain project development milestones. The term loan and cost overrun facilities mature on December 31, 2014, subject to acceleration in the event that future projection estimates of remaining reserves in the project area have declined to less than 25% of the level initially projected by Carrizo UK and the lenders. Letters of credit under the post-completion credit facility mature on December 31, 2016. An amendment to the facility was executed on April 17, 2012 which adjusted the repayment of the amounts outstanding under the term loan or cost overrun facility to the following: (i) 45% will be due on June 30, 2013, (ii) 20% will be due on December 31, 2013, (iii) 20% will be due on June 30, 2014, and (iv) the remaining 15% will be due on the final maturity date of December 31, 2014.

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The Huntington Facility requires Carrizo UK to enter into certain hedging arrangements in order to hedge a specified portion of the Huntington Field project's exposure to fluctuating petroleum prices as well as changes in interest rates or exchange rates, and permits Carrizo UK to enter into additional hedging arrangements. The Huntington Facility places restrictions on Carrizo UK with respect to additional indebtedness, liens, the extension of credit, dividends or other payments to us or our other subsidiaries, investments, acquisitions, mergers, asset dispositions, commodity transactions outside of the mandatory hedging program, transactions with affiliates and other matters.

The Huntington Facility is subject to customary events of default. If an event of default occurs and is continuing, the Majority Lenders may accelerate amounts due under the Huntington Facility.

As of June 30, 2012, borrowings outstanding under the Huntington Facility were \$37.0 million, of which \$16.7 million was classified as current, with a weighted average interest rate of 3.97% and no letters of credit had been issued.

Critical Accounting Policies

The preparation of financial statements in accordance with U.S. generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in our Annual Report on Form 10-K for the year ended December 31, 2011. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, income taxes and commitments and contingencies.

The table below presents the 12 month average oil and gas prices used in our June 30, 2012 U.S. full cost ceiling test and related cushion along with various pricing scenarios to demonstrate the sensitivity of our U.S. cost center ceiling to changes in 12 month average oil and/or gas prices. This sensitivity analysis is as of June 30, 2012 and, accordingly, does not consider drilling results, production and prices subsequent to June 30, 2012 that may require revisions to our proved reserve estimates.

Scenario	12 Month Average Oil Price (\$/Bbl)	12 Month Average Gas Price (\$/MMbtu)	Cushion/(Impairment) (in millions)
Actual - June 30, 2012	\$101.15	\$2.27	\$129
+10% Oil / +10% Gas	\$111.26	\$2.50	\$270
-10% Oil / -10% Gas	\$91.03	\$2.04	\$(63)
+10% Oil / 0% Gas	\$111.26	\$2.27	\$227
-10% Oil / 0% Gas	\$91.03	\$2.27	\$(17)
0% Oil / +10% Gas	\$101.15	\$2.50	\$175
0% Oil / -10% Gas	\$101.15	\$2.04	\$83

The cost center ceiling exceeded our net capitalized costs for the U.K. cost center at June 30, 2012 by approximately \$131.9 million and was based on 12 month average oil prices of \$108.48 per barrel. A ten percent increase in average market prices at June 30, 2012 would have increased the cost center ceiling by approximately \$19.7 million and a ten percent decrease in average market prices would have decreased the cost center ceiling by approximately \$19.7 million. This sensitivity analysis is as of June 30, 2012 and, accordingly, does not consider drilling results and prices subsequent to June 30, 2012 that may require revisions to our proved reserve estimates.

Volatility of Oil and Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and gas.

We review the carrying value of our oil and gas properties quarterly using the full cost method of accounting. See "Summary of Critical Accounting Policies – Oil and Gas Properties," in our Annual Report on Form 10-K for the year

ended December 31, 2011.

We rely on various types of derivative instruments to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure program. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received

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or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production for up to 36 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at June 30, 2012, and December 31, 2011 was a net asset of \$58.6 million and \$37.3 million, respectively. The following sets forth a summary of the net fair value of the Company's derivative instruments by counterparty:

Counterparty	June 30, 2012	December 31, 2011	
Credit Suisse	52	% 68	%
BNP Paribas	27	% 19	%
Societe Generale	11	% 2	%
BBVA Compass	6	% —	%
Shell Energy North America (US) LP	2	% 6	%
Credit Agricole	2	% 5	%
Total	100	% 100	%

Master netting agreements are in place with these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the financial viability of our counterparties. Because Credit Suisse, Credit Agricole, BBVA Compass, and Societe Generale are lenders under our Revolving Credit Facility, and BNP Paribas and Societe Generale are lenders under our Huntington Facility, we are not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties, as the contracts are secured by the Revolving Credit Facility or the Huntington Facility, respectively.

The following sets forth a summary of our U.S. natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of June 30, 2012:

Period	Volumes (in MMBtu)	Weighted Average Floor Price (\$/MMBtu)	Weighted Average Ceiling Price (\$/MMBtu)
2012	11,132,000	\$4.96	\$5.13
2013	10,950,000	\$5.07	\$5.07
2014	3,650,000	\$—	\$5.50

In connection with the natural gas derivative instruments above, the Company has entered into protective put spreads. For the remainder of 2012, at market prices below the short put price of \$4.41, the floor price becomes the market price plus the put spread of \$1.02 on 4,296,400 of the 11,132,000 MMBtus and the remaining 6,835,600 MMBtus would have a floor price of \$4.96.

The following sets forth a summary of our U.S. crude oil derivative positions at average NYMEX prices as of June 30, 2012:

Period	Volumes (in Bbls)	Weighted Average Floor Price (\$/Bbl)	Weighted Average Ceiling Price (\$/Bbl)
2012	883,200	\$86.15	\$105.91

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2013	1,861,500	\$ 87.57	\$ 104.82
2014	1,095,000	\$ 91.75	\$ 103.88
2015	620,500	\$ 92.79	\$ 97.18

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For the three and six months ended June 30, 2012 and 2011, we recorded the following related to our oil and gas derivative instruments:

	Three Months Ended		Six Months Ended	
	June 30, 2012	2011	June 30, 2012	2011
	(In thousands)			
Realized gain (loss) on derivative instruments, net	\$ 9,887	\$ 4,904	\$ 21,020	\$ 14,910
Unrealized gain (loss) on derivative instruments, net	28,360	7,161	20,265	(3,032)
Gain (loss) on derivative instruments, net	\$ 38,247	\$ 12,065	\$ 41,285	\$ 11,878

Forward Looking Statements

The statements contained in all parts of this document, including, but not limited to, those relating to the Company's or management's intentions, beliefs, expectations, hopes, projections, assessment of risks, estimations, plans or predictions for the future, including our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, timing and amounts of production, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of oil and gas exploration, acquisition of 3-D seismic data (including number, timing and size of projects), capital expenditure plans, planned evaluation of prospects, probability of prospects having oil and gas, expected production or reserves, pipeline connections, increases in reserves, acreage, working capital requirements, commodity price risk management activities and the impact on our average realized prices, the availability of expected sources of liquidity to implement the Company's business strategies, accessibility of borrowings under our credit facilities, future exploration activity, drilling, completion and fracturing of wells, land acquisitions, production rates, forecasted production, growth in production, development of new drilling programs, participation of our industry partners, exploration and development expenditures, the impact of our business strategies, the benefits, results, effects, availability of and results of new and existing joint ventures and sales transactions, proceeds from sales, and all and any other statements regarding future operations, financial results, business plans and cash needs and other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words "anticipate," "estimate," "expect," "may," "project," "plan," "believe" and similar expressions are intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under our credit facilities, evaluations of the Company by lenders under our credit facilities, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information, property acquisition risks, availability of equipment, actions by our midstream and other industry partners, weather, availability of financing, actions by lenders, our ability to obtain permits and licenses, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture partners, results of exploration activities, the availability of and completion of land acquisitions, completion and connection of wells, and other factors detailed in the "Risk Factors" and other sections of our Annual Report on Form 10-K for the year ended December 31, 2011 and in our other filings with the SEC, including this quarterly report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their

entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For information regarding our exposure to certain market risks, see Item 7A. “Quantitative and Qualitative Disclosures about Market Risk” of our Annual Report on Form 10-K for the year ended December 31, 2011. There have been no material changes to the disclosure regarding our exposure to certain market risks made in our Annual Report on Form 10-K for the year ended December 31, 2011.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to provide reasonable assurance that the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. They concluded that the controls and procedures were effective as of June 30, 2012 to provide reasonable assurance that the information required to be disclosed by the Company in reports it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. While our disclosure controls and procedures provide reasonable assurance that the appropriate information will be available on a timely basis, this assurance is subject to limitations inherent in any control system, no matter how well it may be designed or administered.

Changes in Internal Controls. There was no change in our internal control over financial reporting during the quarter ended June 30, 2012 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

Item 1A. Risk Factors

There were no material changes to 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.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuance of Warrants to Purchase Common Stock under the Land Agreement. On November 24, 2009, the Company entered into a Land Agreement, as amended (the "Land Agreement"), with an unrelated third party and its affiliate. In April 2012, the Company issued warrants to purchase 25,000 shares of the Company's common stock to the third party's affiliate for leases acquired prior to the expiration of the Land Agreement. The April 2012 issuance was the final issuance of warrants under the Land Agreement. The warrants are subject to antidilution adjustments and may be exercised on a "cashless" basis. The warrants were issued pursuant to an exemption from registration under §4(2) of the Securities Act of 1933, as amended.

See Note 7. Shareholders' Equity for further discussion of the Land Agreement.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

In November 1999, we entered into a month-to-month agreement, as amended, with San Felipe Resource Company, an entity owned by Mr. Webster, under which Mr. Webster provides consulting services to the Company in exchange for a fee of \$15,000 per month. In his capacity as a consultant, Mr. Webster was granted awards under the Company's

Incentive Plan. As a result of such arrangement, Mr. Webster generally did not receive the compensation otherwise granted to our Board members. On May 16, 2012, Mr. Webster and the Company terminated this agreement. Mr. Webster will now receive as a board member a retainer of \$180,000 per year, and will be entitled to the same meeting attendance fees as other members of the Board (i.e. \$2,500 per meeting attended in person and \$1,000 per meeting if attending telephonically), together with an equity award of shares of common stock of the Company, with such compensation and award of shares to be reviewed and determined on an annual basis by the Compensation Committee.

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Item 6. Exhibits

The following exhibits are required by Item 601 of Regulation S-K and are filed as part of this report:

Exhibit Number	Exhibit Description
*31.1	– CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	– CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	– CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	– CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	– Interactive Data Files
* Filed herewith.	

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SIGNATURES

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

Carrizo Oil & Gas, Inc.
(Registrant)

Date: August 8, 2012

By: /s/ Paul F. Boling
Vice President, Chief Financial Officer and Secretary
(Principal Financial Officer)

Date: August 8, 2012

By: /s/ David L. Pitts
Vice President and Chief Accounting Officer
(Principal Accounting Officer)